INTEGRATED ENERGY POLICY REPORT

2004 UPDATE COMMITTEE'S 4TH WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	)	
	)	
Informational Proceeding and	)	Docket No.
Preparation of the 2004 Integrated,	)	03-I3P-01
Energy Policy Report Update	)	
(2004 Energy Report Update)	)	
	)	

CALIFORNIA ENERGY COMMISSION

1001 I STREET

CENTRAL VALLEY ROOM

SACRAMENTO, CALIFORNIA

THURSDAY, AUGUST 26, 2004

9:00 A.M.

Reported by:
Peter Petty
Contract No. 150-04-002

COMMISSIONERS PRESENT

John Geesman, Presiding Member

James Boyd, Associate Member

ADVISORS PRESENT

Melissa Jones

Chris Tooker

Darcie Houck

STAFF

Sandra Fromm, Assistant Program Manager

Matt Trask

Robert Weisenmuller, Consultant

Rick York

Eileen Allen

ALSO PRESENT

Gregory Blue
Dynegy

Tim Heming
NRG Energy, Inc.

Vitaly Lee
AES Pacific, Inc.

Trent Carlson, Director, Asset Commercialization
Reliant Energy

Steven Goschke, P.E., M.E.
Duke Energy

ALSO PRESENT

Les Guliasi, Director
Pacific Gas and Electric

Barry R. Flynn, P.E.
Flynn RCI

Mary Jo Thomas
CAISO

Roy Craft, General Manager
Reliant Energy

Robert Lawhn, Director
Reliant Energy

Mark Osterholt, Direct, Business Operations
Mirant

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P R O C E E D I N G S

9:00 a.m.

MS. FROMM: Good morning. I'm Sandra Fromm, the Assistant Program Manager for the 2004 Integrated Policy Report Update. I'd like to welcome you here today and thank you for your participation.

Today's workshop will be on aging power plants. This is one topic in a topic of three elements that will be included in the 2004 Update. This update also includes renewables and transmission.

A draft committee summary document will be due out September 15. We will hold hearings around the state on all three topics during the end of September and early October. We will release the final committee document on October 20, and it will be heard before the full Commission for consideration on November 3. After that, we will transmit the document to the governor.

You can participate in today's proceedings by e-mailing us. The e-mail is ieprhearing, and that is one word, @energy.state.ca.us. If you are here today and you wanted to talk, please fill out a blue card or hand me or Matthew Trask your business card, and we can provide to the court reporter.

We also have a comment sheet at the back of the room. If you don't want to come up and speak at the podium, you can fill out some comments at the back of the room at the end.

We welcome your written comments and would appreciate receiving those by September 7. The presentations made by staff today will be posted on the web. Paper copies of staff's presentations are available along with today's agenda and copies of the draft, Aging Power Plant Study, on the table at the back of the room.

When speaking today, if you could speak directly into the microphone and either spell your name and provide the court reporter with your business card if you have one.

There may be a fire drill at some point. If so, please exit the building and meet over at the park, and they will let us know when we can come back into the building.

If we are here during lunch, there is a snack shop downstairs on the first floor. There are also cafes in the park and along J Street. The restrooms are out the doorway, the hearing room doorway, to your left.

Again, I would like to thank you for participating today. With that, I would like to turn the workshop over to the committee.

PRESIDING MEMBER GEESMAN: Thank you, Sandra. Let me apologize for the formality of this particular space. At the same time, thanks Secretary Tamminon and the ARP for making this space available to us.

We thought it would be a good idea to utilize a venue that would facilitate greater access over the internet to this particular hearing. We have received written comments from a number of parties. I wanted to ask Sandra are those accessible through our internet site, or is there some record as to who has actually submitted written comments. I know they have been docketed.

MR. TRASK: We will get them on to the internet site.

PRESIDING MEMBER GEESMAN: I think that would be helpful. We've got a full schedule planned, so I don't really intend to make any introductory comments. I think that this is a pretty well-informed audience that has followed our process since we initiated it last fall, and I look forward to the presentations and discussion over the course of the day.

Commissioner Boyd?

COMMISSIONER BOYD: Thank you, John. I don't think I want to take any more time to add anything, so I think we should just get underway. I'd just like to welcome all of our advisors. We have a full slate here today, both of yours and Darcie Houck and Mike Smith, my advisor, with us.

This process and procedure has generated a lot of interest and a lot of paper, so we are all anxious to hear about the future in this issue. So, thank you.

PRESIDING MEMBER GEESMAN: Matt, do you want to start?

MR. TRASK: Yeah. Good morning. I'm Matt Trask. I'm the Project Manager for what we've called the Aging Power Plant Study. We gave it a considerably longer name when we turned it into a white paper.

I just wanted to talk a little bit first about the purpose of today's workshop. We are here primarily to hear from you, to take comments on the study, and to see if we got it right. We have sort of three general requests from you up there, are our conclusions accurate and appropriate. Did we accurately capture your input, and are there other factors to consider.

As Sandra said, the draft, white paper, and your comments today will both become part of the record that the committee will consider when preparing their own report.

I'm going to start off with just a short presentation on the study. Like Commissioner Geesman said, those that have been following the proceeding are fairly familiar with what is in it, and we have given several presentations before. Today I am going to more or less the highlights.

Following the presentation, we are going to have a period where we can have other presentations or general comments and then following that, we are going to have more focused discussions, and we will take specific comments then. We are going to go essentially chapter by chapter through the APS, the Aging Plant Study. We are going to be following along the set of questions that were included in the agenda up front there. If later on you haven't got a copy of that agenda, you may want to grab that, and we will be using those questions to focus our discussion.

It's been a long and interesting study. We started off with selecting a group of power plants that we thought was representative of what we are calling the Aging Power Plant Sector. Out of the approximately 1,500 generating units in California, we selected 66 of them. It is totaling about 17,000 MW, which is about 25 percent of the total generation. As you can see, these are fairly large plants.

The red dots are where they are located up there. You can see we have one way up north, Humboldt County near Eureka. We have four in the Bay Area, two in the Central Coast, and then 15 in Southern California.

The study starts off with something we think is rather important is some definitions of terms that sort of get thrown around. We found that there really wasn't any sort of solid definitions of some of these terms. Local reliability is probably one of them. It is kind of sort of a chicken and egg thing.

The ISO in their studies they conclude that there are nine local reliability areas in California. These are areas generally defined by their criteria, reliability criteria. The ISO and the utilities do studies where they simulate the electric grid, and then they will cause things to fail. A generator will go out, a breaker will fail.

In general, we are defining local reliability areas as any place where the failure of two components, a generator and a breaker, or something like that would create outages or at least compromise power quality.

Beyond that, we discussed quite a bit "Regional Reliability". In California we have three general regions, which are more or less defined by our transmission system. I apologize that you can't see this very well. We are sort of limited in the transmission maps that we can use in a public forum because of security reasons.

In general, we have three very large regions. We have Northern California up here, which is north of Path 15. Path 15 is this transmission line right in through here. It belongs to PG & E and is the major route for getting power from the north to the south or vice versa.

Because of its limitations, it is kind

of a bottle neck, and that is what creates these three regions. We have the Northern Region, which is north of Path 15, Southern Region south of Path 15, and then we have a much smaller region which is right along Path 15.

We refer quite a bit to regional reliability because there is a very limited amount of power that can be transferred from one region to another, so the power plants that are in those regions become very important for maintaining reliability.

We also talk quite a bit in the study about some sub-regions, primarily we are talking about the Los Angeles area, the greater Los Angeles area, and a few other areas like the San Francisco Bay Region. Now, we looked at these as kind of a special case, especially in Los Angeles.

As you notice, there are several major transmission lines that are coming in to the LA area, and at any one time, you could have congestion on any one of these lines. You can have congestion on all of the lines. What the control area operators in that region do is they are constantly balancing load with generation, and they are also constantly balancing these transmission lines by using the end region generation, which here are denoted by the yellow dots. Those are all the aging power plants in the Los Angeles Basin.

When transmission lines start to get congested in that area, the control area operators will generally instruct the plants in the region to start adjusting voltage levels, adjusting power levels to help alleviate the congestion on the transmission lines.

Let's get into a little bit just a brief summary of the report. We started out with describing the role of the aging power plants. We first looked at the 66 units. Then after some discussions with the owners of the units, we determined that 50 units were more appropriate for looking at reliability problems and so forth. The other 16 are owned mostly by municipal utilities or PG & E. We concluded that they will not retire during the study period, which is 2004 through 2008. So, we focused mainly on these 50 units, which are owned by private companies.

We came up with five things that they mainly do. They provide reliability services in select areas through the California ISO's RMR process. Again, perhaps the easiest way to see where one of these is needed is way up north in Eureka. We have the Humboldt plant right up there in Eureka. There is really only one major transmission that comes out from the I-5 corridor out to that area. There are some smaller transmission lines that distribute down south, but really only one line out to that population center. That power plant out there becomes very important for maintaining voltage and frequency in that area, and therefore is designated as a RMR Reliability Must Run plant.

Some of the other services that they provide is regional reliability by acting as a margin of reserve for use during supply emergencies. We see this generally in the summer, hot months, but not always. We had an anomaly this year in late March where we had a heat spike and then a lot of power plants were off line. Some of these aging plants were crucial in maintaining regional reliability during that shortage.

Those that are owned by municipal utilities are operated a little bit different. They generally provide base load as well as other services and are usually very near the load centers, so they are quite cost effective for those municipal owners.

They are very important, like I said for meeting incremental demand during the hot summer days and any other time when we have a generation shortage. As I briefly discussed earlier, they are also used to alleviate transmission system congestion by offsetting inter-tie overloading at or near the load.

After we talked about the role of the power plants, we then went into our reliability analysis. This analysis was two-fold. We looked at the effect of retirements of plants on the transmission grid, but then conversely, we also wanted to make sure that if we continued to rely on these units, that they were reliable themselves and would be there when we need them.

The first thing we did was to rank these plants by retirement risk, either high, medium or low. This is an important factor. We did this ranking only relative to the study group. It really is mostly for us to try to start our analysis of the effects of these retirements. We wanted to examine a wide range of possible retirements, so we just came up with this scenario more or less of what we thought might be the likely future for these plants. Mostly it is based on fairly simplistic criteria. That is whether or not they have a contract.

If a unit has a contract, either an RMR contract or a contract associated with the Department of Water Resources contracts, and it is through the entire study period, we assume that those were low risk of retirement.

If they have a contract, but they might lose them during this study period, say if it is an RMR plant or another plant is built that might assume that service or transmission line is built, then that RMR is not longer needed, that plant could lose that RMR contract. So, if that happens during the study period or if we think it might happen, then we assign that as a medium risk.

Those that have no contracts at all at the present and really no prospect given the present market design of getting a contract, we consider those at high risk. These are described in Table 3.1 and 3.2 on page 41 of the Aging Plants Study.

There are some other factors that we

used to sort of edge the rankings one way or another. For instance, the South Bay Plant is the subject of an agreement with the Port of San Diego. It is rather a complex agreement, but there is some possibility that this plant would be shut down. The South Bay Plant would be shut down within the study period. Although, it would be likely that if it was shut down, it would be replaced by a new plant nearby or in the same region.

Once we determined which plants were at high, low, or medium risk of retirement, we then conducted powerful analysis in taking out these first five high-risk plants, and then the medium-risk plants in combination, and looked at the effects on the transmission system.

What we found was that indeed the retirement of just about any one of these units can create some problems, some local overloading, and things like that. In general, those kinds of problems can be fixed with relatively easy and cheap transmission upgrades, but not always.

We also looked at the model, the role of these aging plants on alleving transmission system congestion, and in that we looked at Southern

California in the Los Angeles area and in the San Diego area, and also up in the Bay Area.

We determined that the retirement of the plants could have an effect on the ability to import power into the Los Angeles area, but probably not have an effect on the import limits in San Diego or the Bay Area.

As I mentioned earlier, we also studied other projects coming on line, power plants, transmission line upgrades, that could effect the RMR status of certain plants.

We also coordinated with the California ISO and the utilities on their study of reliability effects of retirements. This is a yearly thing that the ISO and the transmission owners do. It is called an "annual grid assessment". PG & E, SDG & E, Southern California Edison are at this moment completing their sensitivity studies on their parts of the transmission grid for the next year. They also look out as far as ten years just to try to predict what will be coming down the line. They identify reliability criteria violations. I briefly mentioned this earlier. That is again what would happen if things started to go wrong, if we lose a generator, if we lost a circuit breaker, things like that. What would happen to the transmission system. They identify any transmission fixes that could come out of this, and then also they identify how you would test to make sure that the system would work.

What is different this year, is that the grid assessments are focusing on the retirements of these aging plants. At first, I thought it was quite good validation that the utilities and the ISO had chosen the exact 50 units that we did for studying reliability effects of retirements. As it turns out, that is not too unreasonable since they are the oldest and largest plants. It was a very obvious assumption.

Like I said, they are looking at the exact same 50 units that we are. They are modeling the exact -- doing the same thing that we did, only they are taking it to a much further and deeper level. That is why I encourage everybody here to at least visit the ISO's website. I've got the web address up there, and for those of you listening in on the web, this will be posted on our website hopefully any minute now. Anyway, the Energy Commission is involved in that study, it should be out this fall sometime, and it should provide quite a bit of additional information about the effects of retirements.

We also looked at the reliability of the units themselves. It turned out to be a pretty interesting investigation. We tried to gather data on forced outage rates. There are some agencies that collect this data, primarily the North American Electric Reliability Council, however, it is not mandatory, and so the data submission is somewhat uneven. It is difficult to compare from region to region, so we didn't get a lot of information out of that source.

One place we did find quite a bit of useful information is in the Continuous Emissions Monitoring System Data Base that the US EPA keeps. This is a very massive data base that has power levels and emission levels of 62 of the units out of 66 that we are studying. It provided quite a bit of good information.

We were able to determine that when these plants are needed during those hot hot summer months, they are generally available and they generally have about the same forced outage rates and new plants.

We also determined through the studying of this data but also talking with the generator owners, including the municipal plant owners, that it is pretty widely accepted that your forced outage rate is going to be inversely proportional to the maintenance spending that you do on these units. The more maintenance you do, the lower forced outage rate you have.

The data also suggests that the life of these plants can be extended almost indefinitely with the proper maintenance program. They are fairly comparatively simple to some of the new plants, not a lot of things to break down. So, if you do your maintenance, they can last a long long time.

After that, we looked at the future of the aging power plant operations. We do see that the investor-owned utilities are likely to need at least an additional 5,000 MW of capacity in the summer of 2005 and another 5,000 MW by the end of 2009. This capacity primarily will be peaking and load-following, not base load. There is plenty of base load already out there.

We don't see much of a near term energy need for those utilities until we get into 2007 or so. I should say outside of the summer. Once we get to 2007, there will needs for some energy in other seasons.

The ability of these aging plants to participate in the future markets and to fulfill some of this capacity energy need is going to be largely dependent on the future market design resource adequacy procurement, and so forth, primarily the subject of proceedings at the California Public Utility Commission.

Following looking at the future, we started to think about well, if they do retire, what would rise to replace them. In general, we assume it would probably be a mix of several things. I've got them up there on the screen. It is going to be a mix of demand-side management (efficiency and conservation) as well as demand response, which are programs to reduce the peak, the needle peaks, in the very hot summer days, as well as renewable energy development, increase generation, existing power plants, new power plants, and transmission upgrades, and new lines.

The exact mix of those replacements is likely to be very different depending on which unit retires. For instance, some areas have already done quite a bit of demand-side management, and there may not be much potential for more. Other areas, there is a great deal of potential for increased demand-side management.

We did determine that in short term, for instance if a unit was to retire this fall unexpectedly, that most likely the replacement for that generation would be from existing plants, followed later by the newly constructed plants.

If you look at the generation that is available right now to replace these plants, as well as the new plants coming on line, there is a possibility to either increase or decrease fuel use and environmental impact from the present situation, depending on the mix of technology that rises to replace these generators.

For instance, we think some of the generators if they were to retire, the most likely replacement would be existing peaking plants. These peaking plants definitely have higher emissions and lower efficiencies than the boiler units. It is really dependent on the mix of technologies that are employed to replace these units as to what the result and effect on fuel use and emissions would be.

In our environmental chapter, Chapter 6, we looked quite a bit at air emissions as well as biology. What we determined with air emissions is that these plants are very well controlled already. I think all but 20 of them do have the best available retrofit control technology installed, which is selective catalytic reduction, SCR. Those other 20, some of them will be installing SCR over the next few years. Others comply with Air District criteria through other means, either operating caps. Some have done other sorts of emissions upgrades, low NOX burners, and things like that.

We determined that in the way these plants operate -- I should back up a little bit. What we determined was that these plants have emission raters per term of gas burned, essentially identical to new combined-cycle plants. However, they are 10 to 15 percent less efficient than these new plants. Their emission rates per MW hour are about 10 to 15 percent higher than new plants.

This was an interesting phenomenon that came out of our study. If you looked at the name plate data on these units, the aging units compared to a new combined-cycle unit, you would think they are considerably less efficient, 30 to 40 percent less efficient. When you look at the way that they operate in load-following mode and starting out at low power levels in the morning and increasing through the afternoon and then tapering off in the evenings, combined-cycle plants don't do well at low power levels, so they have higher emission rates at that level. They have worse efficiency. As opposed to the aging units which are generally linear. They have the same emission rates no matter what power level you are at.

When you look at that combined or aggregate fuel use and emissions, it is really only about 10 to 15 percent different than new plants.

As far as the way they fit into the mix, in 2003 the aging plants produced 28 percent of the electricity in the state, but only 15 percent of the generating sector NOX emissions. That means that there's quite a few power plants out there that have considerably worse emissions than these aging units.

Next we looked at the impacts and the

expected effect on retirements from regulations governing once-through cooling facilities. These are generally facilities that use sea water or bay water to cool the plants. Eighty percent of the aging units under study used these systems, obviously the ones on the coast and in the Bay Area.

There are new Clean Water Act regulations that the Environmental Protection Agency just put out. They put out the first one in February, and I believe they were adopted in April or May. We don't believe that these new regulations are going to effect aging plant operations during the study period. There is quite a bit of leeway in how plants can comply with the rules, and then there is also quite a bit of leeway on when the process would start. They are generally associated with the expiration of NPDS, permanence governing the water quality of the sea water that they use.

It looks like things won't really start kicking in until 2009, 2010 area. After that, staff has determined that there is a pretty large information gap about what could occur as a result of these new regulations, especially concerning cumulative impacts. Actually, one of the things we did recommend out of this study was to follow up on this area and see what could be done to improve the science and the knowledge of this area.

That's it in a nut shell. Like I said, hitting the high points. What is next, as Sandra briefly mentioned, was the Committee will be putting out its own report in mid September. Staff will be conducting additional analysis and gathering some data, especially on regional supply and demand, balance, and congestion relief.

We had actually hoped to do a little bit of a presentation, breaking down the reserve margins in the regions, the three regions I discussed earlier north and south of Path 15 and along Path 15. We just weren't quite confident to put out our numbers today. What we are planning to do is to put this up on the web, our break down of supply and demand in the different regions and then try to asses the reserve margins that are available in those regions.

We will put that up on our website and seek your comments on those. We will see if we got our assumptions right. There will be hearings in late September and early October on the Committee's initial draft. As Sandra mentioned, the final report in late October.

That is it for my presentation. Short and simple. If people have questions in general about the study, we can probably answer those now, but we had planned at this point to have some presentations and general comments from parties on this study. So, unless there is some questions right now, I thought we would go ahead into the presentations by other parties.

Greg.

PRESIDING MEMBER GEESMAN: Greg, I think you need to make certain that the green light is on, on that microphone.

MR. BLUE: Hello. It sounds on. Can ya'll see the presentation, the screens in front of you? Great. My name is Greg Blue. I work for Dynegy.

I am talking today on behalf of West Coast Power. West Coast Power is the entity that owns our power plants in California. The 50/50 joint venture between Dynegy and NRG Energy. Also with me today presenting the environmental piece of our comment is Tim Hemig, Director of

Environmental Affairs for NRG Energy. Thank you.

In general I would say that what I am going to talk about today is I am going just share with the Committee here some of what we consider highlights out of the report, also some oversights that we see that are not in the report. Then I am going to go chapter by chapter with some just general observations and comments.

We have filed written comments. I just wanted the committee to know that we take this very seriously, this Aging Power Plant Report. This is our written comments with our presentation attached. We spent a lot of time effort in this. We think this is a very important study, and I want to commend the committee and the Commission for engaging in this staff.

I think before I start, I saw this letter yesterday for the first time from Commissioner Peevey. He wrote to the governor this Monday. There is a paragraph in there I think where my point is I think the PUC recognizes this is an issue. I know the ISO has recognized this is a big issue, but just for the people in the audience and who are listening, I will read one short paragraph, "Further, to meet the near term energy needs of California, the Commission is working closely with the Independent System Operator and the investor-owned utilities to insure that existing power plants are kept operational until they can be replaced with newer, cleaner, and more efficient plants. While these aging power plants need to be replaced, in the near term they are an essential part of California's electricity infra structure, especially in a few key areas of the state."

We endorse that comment and agree with that comment. We believe that some of these plants will have to be replaced in the future. That is one of the things I am going to talk about in a few minutes.

Some of the highlights that I know Matt had talked about, but from our point of view, some of the key highlights that we have seen in this report is that aging power plants continue to play a vital role in reliable delivery to California consumers. That little statement was one little sentence, but it is really key to this whole discussion here. We agree with this.

The other important thing that came out of the study validated the comments that we had made in the 2003 Integrated Energy Policy Report regarding what we considered plants that were at higher risk of economic retirement. We had submitted some numbers in that proceeding. We came up with about 10,500. Since then, retirements have happened and so forth.

In this report, the staff has come up with a number of 8,543 MW that are higher risk for economic retirement. The numbers are a little bit off, but basically I think the general assumption is it validates some of the things we were saying.

The other thing I think is important is the locational value of the plants is being recognized in the report. That is really big I think. I will talk a little bit more about that later.

Two things, one it provides local reliability service by alleviating the transmission congestion that is occurring right now in SB 15. Another really important point that I don't think has come up until this report was that it provides sub-regional reliability service by allowing the import limitations to be fully utilized. We will talk a little bit about that later.

I think the report when they are focusing on the LA Basin makes some pretty interesting conclusions there. The next bullet there, retirements within the LA Basin sub-region, could reduce the capability of importing power into the area.

The last is, of course, it is no surprise to us that owns these power plants, that in fact without our RMR, DWR, or other contracts, based on the current market designs, we have limited ability to recover our cost. That is going to be a problem, and really it is a nearer term problem than the report indicates. We will talk about that.

Some of the other highlights we found are some of the things that Matt had mentioned, that the operational data shows that in fact the aging generation is closer in efficiency to newer combined-cycle than the name plate data indicates. It is not as bad as some had thought.

I think the next two bullets are my David Freeman bullets. He had continually called us dirty old plants, and I'm going to have to find out where he is and mail him a copy of your study. Most of the aging fleet and all of our units have been retro-fitted with SER, and we are in full compliance with the all-air quality standards.

The retro-fitted units have emission rates per therm of gas burned, essentially identical to newer combined-cycle plants. In fact, the average emissions of the aging generation is better than the simple cycle-combined turbins.

One other highlight, the expected cost of compliance with new regulations on once-through cooling are not likely to drive retirement decisions in this study time period, and Tim is going to talk about some of those issues.

Some of the oversight that we saw in this report, I think everybody on the committee have heard me on this one before, but I'm going to keep repeating it. There is no discussion on the value of repowering at the critical existing load pocket sites. While the report talks about new generation being needed and the report talks about additional generation coming from other existing plants, it really does not have enough discussion in our opinion on repowerings. Clearly we think that is an important policy position, and I will talk a little bit more about that.

We need additional discussion on land use and socio economics. In fact, one of our recommendations at the end of this is that you have a separate Chapter 7 for that topic. Right now it is a sub-section of Chapter 6, and it is not a separate chapter. We believe that there are a lot of issues there that need to be discussed, and I think you need to be talking to some of the local municipalities where these power plants are located to find out how critical they are to their own local budgets and so forth.

There is no discussion on the synergies between these (indiscernible) plants and the existing coastal power plants. There is a brief mention of it under land use. These are out there. We provided some comments on that topic.

Last week at the 2005 Scoping Committee Workshop for the '05 IEPR, there was a presentation by Lon House of the California Water Agency which dramatically highlighted the water issues in the West and the fact that in his opinion and he is speaking on behalf of the Association of Water Agencies, that this allination plants are a given and they are coming to California. They are much needed.

That issue has to do, of course, with these existing plants that are located on the coast that if the right policies aren't in place, there is a potential that some of these plants could be -- the sites could be lost forever. I know that there are people contacting us on our plants frequently inquiring about long term use of this land right there on the coast.

The report that another oversight did not examine what forms of capacity markets and levels of capacity compensation might be required to retain aging generation or attract new generation. It mentions, but does not take any position on what we think is critical having to do with the deliverability standards.

Last is that there is a lot of good data in here, really good data. There is not enough policy recommendations in this report, and I am hoping -- maybe I just don't understand it. Maybe the policy recommendations come from the Committee report and that gets added in on top of the staff report. I am just not familiar. Maybe that is how it works. I hope so. We will be giving you some recommendations.

When I say policy recommendations, one

of the things that I am talking about is for example, supporting your sister agencies in their efforts, supporting or making recommendations to the legislature or the governor on certain issues, writing a letter. It seems to be everybody is writing letters these days. Maybe a letter informing some people or the governor of some of your findings out of this report I think would be very important.

Again, I have to say this every time I get up here. Time is of the essence. What we have found out since the beginning of this process is it has become imperative that we maintain our existing generation. We have seen load growth in the West, it has been robust. Not only in California, but Arizona, New Mexico, Nevada, we have seen the record peaks this summer, load has increased about six percent from '03. Of course every time we have a heat wave -- we've been really lucky with cool weather again this year in general. It's going to be hot this weekend, but it is getting cool again next week. Still, no state policy on repowerings.

The tradeable capacity markets are still in the discussion stages. The PUC has finally taken off this MDO 2 title. We have quietly buried that title, and now it is MR 2, which is still years away from implementation. The most important point is the owners of these power plants are having to make business decisions now for 2005 and beyond. We are really looking for some guidance on what we are going to be seeing out there from not only the Energy Commission, the governor's office, the PUC, and the other agencies.

The next slide is what we did is this shows the magnitude of the problem out there. The staff has identified 8,542 MW that are at higher risk of retirement. All this is, is just for display purposes only, as I say. It is not a prediction of anything at all. It is just showing the magnitude of the problem. If you were to have those MW's off the system this year in the five peak days we've had or is that six peak days, you can see it is not good. This is just to represent the magnitude of the problem that we are talking about and why it is so important to develop policies that maintain some of these existing plants in the short term and in the long term support repowering on some of these plants.

Starting on Chapter 2, the role of aging generating units. As the report identified that these aging fleet will be needed to meet the energy needs at peak demands over the next three to five years. Depending on how new plants come on line, it could even be longer.

Another important point that came out of this report was that the energy used to alleviate some of the intra-zonal congestion down in SP 15 particularly, is coming from the FERC imposed must-offer requirement.

The must-offer requirement is a temporary requirement in our opinion and can be revoked by FERC at any time. Our opinion is once resource adequacy requirements are in place, there is a high likelihood that FERC is going to remove that. This was put into place as a temporary stop gap measure, I don't know how many years ago it was, but several years back. So, we think that this -- and when I get to the recommendations at the end, this needs to be acknowledged in the report and what does that mean.

The next bullet is we believe that there is a permanent role for existing sites in providing local reliability services. That feeds into my point, and this is what the report brought out, the draft white paper brought out that you need some of these plants in these locations. Not only do you need them in the short run, you need them in the long run too.

The solutions in the short run are RMR like contracts, and the long run it has to be repowering at some of these critical locations.

Utilities must be required to procure deliverable energy and capacity in or near the load centers. We think that the PUC has recognized this. We think they are moving towards that. They are working with the ISO. Once again, we haven't seen it happen yet. We have seen the utilities resistant, or at least certainly not volunteer and step up and deal with this issue.

We are hoping that we get the right results coming from the PUC, however, any recommendations or encouragement from the Energy Commission to the PUC would be appreciated on this topic. I will probably, of course, probably come and talk at the Joint Energy Meetings as well as September 8 I bring some of the same message.

PRESIDING MEMBER GEESMAN: Let me say with regard to that, and it applies both to the evolving search for deliverability standard and also approaching this concept of load pockets. Greater clarity will produce a more rapid state government response. I think one of the things the Public Utilities Commission and certainly our commission, and I can't speak for the ISO, are struggling with is the ability to clearly define a standard such as it will be usable in a regulatory forum.

I know from an engineering standpoint, if you don't need to be concerned with the empirical requirements or evidentiary requirements of a regulatory forum, it is a little bit easier to move quickly in some of these areas. I think all of the parties need to recognize, both with respect to deliverability and load pockets, while there seems to be a great convergence of opinion as to the desirability of meeting those needs, there is a great deal of difficulty in precisely defining exactly what it is that state policy should be attempting to do. I think that is a burden all of us share. The quicker we are able to resolve it, I think the quicker we will be able to have satisfactory policies in this area.

MR. BLUE: I agree, and I'll commit to

keep the pressure up on everybody.

Going to Chapter 3, some of these points I will kind of reiterate what I said in the highlights, but basically the fact that retirements of older generating units in Southern California will lower the import capability for SB 15 demonstrates the need to maintain generation at those sites.

I think one of our recommendations is that further study is needed on the impacts of the retirements in San Diego to Edison's reliability because there was a brief mention in there about that there might be some issues associated with retiring the San Diego area plants as it affects the Edison plant. We think that needs to have a little more study on that or a little more clarity.

The other thing on the San Diego Gas and Electric, basically what we saw in the report was the one sentence that said even without any retirements in San Diego, that in the study period, they are facing line overloads even without them. So to us, we just think a little more study needs to be done on the San Diego import limits we think to bring a little more clarity as Commissioner Geesman has mentioned.

The San Diego Gas and Electric analysis, their reliability analysis, in our opinion, should only be valid for one year, from a year to year time frame because basically they are basing it on RMR's that are going to continue to run. I'm going to talk about the RMR issue and what we feel about that basically on the next slide.

RMR, in our opinion, reliability must run contracts do not equal low risk in our opinion. I'll talk about that in a minute. We think plants in the LA Basin that are currently in the chart that is low or medium risk for retirement that did not have RMR contracts should be moved to the high risk category. That is one of the kind of over arching flaws is that the assumption is made that if you have RMR contracts that means you are not likely to retire.

That is not necessarily the case for the reasons I talk about here. There are only one year at a time contracts. They do not support significant reinvestment. The capital additions that we are supposed to be compensated for if the contract terminates at the end of its term and doesn't reup, those have been very contested. It is like a full blown rate case with the ISO every year we try to do a RMR to get your RMR rate set, it is a huge investment in time.

We think, in our opinion, a RMR contracts is more of a survival strategy than anything else. It is really not a long term strategy for California. I believe if you asked the utilities, they would probably agree with that statement as well.

On Chapter 4, The Future of Aging Plant Operations, again resource adequacy requirements and deliverability standards need to be implemented for all those serving entities as soon as possible. Once again, that is probably happening. It is never fast enough for us in our opinion. Even with all the activity that is going on at the PUC, regulatory uncertainty still exists in the market today. Believe it or not, legislative uncertainty also exists in the market today. With all these proposed re-regulation bills and/or energy redesigned bills that come and some go and some don't go, and you know, again, we will probably tackle this issue again in the next legislative session my guess is.

In our opinion, the future of the aging

power plants is dependent on a capacity market or a bi-lateral capacity contract. We think those are developing, but again, any encouragement in this report would be helpful to the other sister agencies.

The issue of debt equivalency, we agree that is a big issue. It is not something that your commission can solve, but acknowledging it as an issue is also something that could be done. I think the utilities would agree on that one as well. We agree that it needs to be resolved.

Chapter 5, Alternatives to Aging Boiler Units, again, as I said previously, repowering will be required in our opinion to maintain the desired level of system reliability. Repowerings are the answer to plant retirements. There is discussion of the local reliability areas and the fact that the importance of some of these sites. If some of these sites go away, it is not an easy task to site a new power plant in California, but it would be even harder in some of these local reliability areas in the future.

PRESIDING MEMBER GEESMAN: Do you think that's proven to be the case in the Bay Area over the last several years? It seems to me that there have been a handful of plants sited in the Bay Area, which is in a local reliability area.

MR. BLUE: I'm really focusing on SP 15, I really wasn't looking at -- focusing in on the Northern California because our plants aren't up there. I would say, yes, you've gotten some through. I was thinking also of going incrementally forward it is going to be more difficult.

PRESIDING MEMBER GEESMAN: But you are speaking primarily with regard to SP 15?

MR. BLUE: To where you have large population areas.

PRESIDING MEMBER GEESMAN: I don't think we've seen the same population of permitted plants in Southern California.

MR. BLUE: Upgrades to the transmission system, also that is another solution is when you do get the transmission system upgrades in place, some of these existing units will have -- if other alternatives come out that alleviate the need for RMR or whatever for the use of these plants, the transmission systems will allow existing units to move some of their power to other markets perhaps.

A lot of those plants are important for

that voltage support and bar support, and not necessarily because of their particular location, as long as they are running, they don't necessarily have to sell to the utility in the service area where they are located.

However, the upgrades to the transmission system needed to reduce the need of the aging power plants will take some time.

Now I am going to hand over to our environmental person, Tim Hemig, to talk about Chapter 6, and then I will return in a minute.

MR. HEMIG: Good morning, my name is Tim Hemig as Greg mentioned. I'm going to be discussing West Coast Power's view of the Chapter 6 in the white paper. Also as stated by Greg, West Coast Power believes the white paper does a good job of discussing these environmental issues and how they might affect operations at existing power plants. However, we think there's a couple of areas where it falls short on some key points.

We did have specific comments in writing on how to improve in those areas. I'm going to raise a couple of those concerns right now. First of all, the environmental benefits associated with redeveloping or repowering an existing site we don't believe are adequately described in the white paper.

Those being that repowering provides greater, of course, efficiencies and natural gas usage, lower emission rates, more efficient use of water resources, and also using existing infrastructure, all of which have environmental benefits.

The white paper does discuss these issues, but we think a more balance evaluation should include more than just one comparison. The comparison in the report is just the Mountain View Plant where a smaller couple boilers, 126 MW were replaced by 1,000 MW facility. In that discussion, it shows that emissions actually increased associated with that.

There are some other examples out there that we think are good examples of repowering existing sites. The El Segundo Modernization Project being one of those, and if you do a comparison of a similarly sized facility like El Segundo, you see you actually get good improvements in short term emission concentrations, I'm talking about parts per million and also emission rates, and pounds per MW hour.

Those improvements are really what affect air quality, it is concentration of emissions. It is not the mass emission rates over the whole year. It is what is coming out of a particular unit in the short term. You do get improvements in repowering with combined cycle and also best available control technology, putting in the best that you can put in, in emission controls. We think those are improvements to air quality, provide net air quality benefits from repowering.

Secondly, when you site a new facility, even if you do have increases in annual emissions, all of those emissions must be off set, and we think that the white paper can do a better job of describing the offset programs so that if a new emissions from a facility increase, they must be fully offset, including at least a 20 percent surplus reduction, as high as 50 percent in some areas.

I think a better discussion of that, showing that there is a net air quality benefit to a repowered project associated with emission offsetting.

Taking these considerations together, I think the white paper includes those in the discussion. You will find that the report actually can't conclude that there are air quality benefits associated with repowering at existing sites, especially if they are comparably sized equipment.

If you add that in along the lines of some of the things I mentioned in the first bullet about water quality improvements, more efficient use of water, more efficient use of fuel, I believe that the report can conclude that repowerings are good environmental policy for California.

PRESIDING MEMBER GEESMAN: You know, I first put that in to an Energy Commission report in the fall of 1979. The Commission's 2nd biennial report. We can say that until the cows come home. I've yet to find many people that disagree with it, but if there is something that you think the state ought to be doing specifically to better promote the concept of repowering existing sites, I'd certainly welcome that specific recommendation. I think that if you are going to see a change in this area, you need to be focused on some specific policies that the state should adopt, and you need to be able to defend those policies.

MR. HEMIG: Absolutely, I think we agree with that. I think in our written comments, we go into that a little bit. One of our recommendations, and Greg will probably mention at the end, is we are looking for some policy support from this kind of a document here that factual describes the benefits and does provide the back up to the facts. The white paper could be improved a little bit in this area.

PRESIDING MEMBER GEESMAN: I'm sure it can. I think my concern is what difference will it make. I think ultimately the investment decision as to whether to pursue repowering at these existing sites ultimately relies on the plant owner and whether the plant owner feels that market conditions are such that it is likely to result in a favorable investment. I think as near as I can tell, the state has been pretty clear over the course of I guess it is 25 years that this is a good idea.

MR. HEMIG: Thank you. Go ahead and go to the second slide there for Chapter 6. The other general area where we think some additional discussion could or some changes to the discussion makes some sense is in the discussion of the 316 B assessment in the white paper.

Generally, I think this is good factual information. There is some good summary of 316 B and Phase 2 316 B regulations that were recently promulgated. However, I think the report goes a little far in discussing some of the issues that really are within the Regional Quality Control Board's jurisdiction. Some of the concluding statements in the report are really better left to the Regional Water Boards to discuss and to make conclusions on.

Two of the specific areas are about the quality of historical studies. A couple of the statements in the report about inadequate data or impacts are much greater than once thought. I don't think those kinds of statements were supported by the Regional Water Quality Control Board's conclusions in their documents such as NPDS permits.

A couple of examples are the El Segundo generating stations permit where the conclusions are that the studies were adequate and the studies do demonstrate that there are no significant impacts and that best technology available is employed at the station.

Of course, recognized that Phase II requirements are different and recognizing that the next several years additional information and additional work will be needed to determine compliance with Phase II. At this point, all we have is what is the status of the existing regulations, and I think those kinds of conclusions should be included in the report about the adequacy of data and demonstration of compliance.

Another more near term example is the South Bay Power Plant has a tentative permit out currently. It did conduct a new entrainment and impingement study in 2003. It was published in 2004. There is a tentative order right now that has some findings, first of which is that current data shows that there is no significant impact on Santa Monica Bay associated with the once-through system.

Secondly, I think most importantly to this discussion since we've brought this up in the past, is that they did find that the new study correlated very closely with 1980's study and found that actually the same conclusions and the same levels of impact, using the new modern methods that I personally don't believe are much different than what was used in 1980. I think it is a good piece of information and should be included. It shows that historical studies may be or in some cases are still representative of what is going on in the sea around the power plant.

The second area is I think it is a little bit early to make some conclusions about how a facility might comply with 316 B. I think that is again better left to the Regional Quality Control Boards and to the owners of the facilities. To make any kind of concluding or judgmental conclusions about the efficiency of available control technology that might be used, I think those kinds of things should be omitted from the report. It is just too early and the information is not yet generated to make those kinds of statements.

The Regional Water Quality Control Boards are really the ones that will make judgements on these issues.

Lastly, Phase II 316(b) requires

significant reductions in baseline impingement and entrainment, but it doesn't actually require evaluation or assessment of direct or cumulative impacts.

There is a cumulative impact section in this white paper. I think it is actually not a relevant section. It is because this new regulation does not focus on that. It focuses on reduction. You figure out what is your baseline and you reduce. So, it really doesn't make a lot of sense to say there is an information gap on cumulative impacts associated with this report. It should be focused on just what Phase 11 regulations require and how that might affect the operation of the facility or retirement of a facility and probably just left at that.

Those are my comments. I can either take questions or later I am going to be participating in a break out session too.

PRESIDING MEMBER GEESMAN: Are there questions?

COMMISSIONER BOYD: Not a question, but a statement as a Commissioner of Record on the El Segundo case. I think I am going to ask that your comments on El Segundo be docketed by the staff in that case if you don't mind. Well, even if you do mind.

MR. BLUE: Thanks, Tim. I'll probably move on to the next one, I guess responding to Commissioner Geesman regarding specific repowering recommendations. What we are hoping is that with -- and we will be making these, in fact, it is part of our written comments, we attached our testimony in the procurement case. West Coast Power filed our own testimony on these issue that is attached, so you guys can see that when you get a chance.

We are hoping that the resource adequacy requirements, the deliverability standards, the results of this report, and the like will combine enough to give the PUC some direction on how to handle it.

Clearly, as far as the owners of these plants making the decision to invest in the repowering or not, depends on if there is a contract out there for repowering to recover your costs. Because as your report stated, if we can't recover our costs in the current market structure, the market redesign is not going to be done until '07 at the earliest, and so we have this gap again of what is going to happen.

If we haven't made enough in our comments here, we will certainly be participating further in this proceeding and try to offer up more concrete recommendations on policy that are defendable. I think at the end of the day when plants are needed in certain locations, they need to be there. If they need to have an RFO or some sort of competition and certain plants win or don't win, we are all big boys. If we are not needed, we are not going to stick around, we will go.

We just think to date there just hasn't been any policy. That is all we are looking for, just some policy, some direction, some recommendations, anything from the State of California, including the governor's office the Energy Commission, the PUC. Believe me, this report is a great step in the first direction in that.

Moving on with the presentation. This is a what we call Chapter 7 in our recommendation that you actually provide a separate chapter on land use and socioeconomics because we think this is a very important piece of the puzzle that needs to be understood by I think the staff and the Commission, which would include things like the desalination projects that were discussed earlier which is in this section right now under land use, we think that is going to be a major piece of California's future and one of the reasons why you need to maintain some of these existing coastal power plant sites.

The other big issue, of course, that got a little bit of mention but really there wasn't a lot of information gathered, and we have, by the way, provided some information in our written comments, which we just filed on Monday regarding property tax that we pay, utility users tax and the likes.

That issue is huge in some of these cities that rely on utility user's tax, franchise fees based on how much cash you burn. Some of the sales tax associated with just the commerce of having a plant located in a certain community is very big.

Our plant down in Encina in the City of Carlsbad, we have a lagoon, which is part of the power plant property. There is all kinds of activities going on there that is listed there.

The sea bass hatchery just released its one millionth fish back into the ocean. We support that facility. We give them a very reduced lease that if they were to lease this property on the open market would be worth hundreds of thousands of dollars a years. We give it to them for dollars a year, things like that, the aqua farm. There is a lot of community benefit that the plants provide.

Our plants provide at least in the minimum of $50,000 a year going back by way of donation, time, and doing things in the local community. I think the communities when you talk to them -- at least our communities where we are located, support us. I can't speak for all communities.

There is a lagoon there, we dredge the lagoon which creates protected areas for special status species, and the dredge sand is deposited on the local beaches for sand replacement. We do that on our own. Nobody is telling us to do that. We do it to help the power plant operations, but we give back to the cities with these types of activities.

Last, some of the recommendations, and I think you have heard me talk about some of these during the presentation, but I will just walk through them again.

The draft staff white paper should support repowering at locations studied in the APBS is good public policy for California.

Another specific thing that we are looking for which we did put in our PUC testimony, we think that the Energy Commission should support repowerings as an explicit resource in the loading order of the energy action plan ahead of conventional supply at green fill locations for all the reasons we talked about in the past.

We think that the Aging Power Plant Study should acknowledge that the FERC mandated most offer requirements can be revoked at any time and what effect will that have on the reliability analysis.

The Aging Power Plant study should not rely on conclusions that the RMR contract guarantees continued plant operations. The Aging Power Plant Study should acknowledge the valuable synergies between desalination plants and existing coastal power plant sites.

Last, the study needs a separate chapter on land use and socioeconomics. We will be here all day to participate in the round table discussions. We have a few other people that have come in. Some of our commercial folks will also be able to be here if we need to answer some certain questions that I may particular not have the answer. I have some people here that I can get some answers from.

PRESIDING MEMBER GEESMAN: Thank you.

COMMISSIONER BOYD: Thank you, Greg. As Chair of the 2003 IEPR, I got to see a lot of you. You should feel pretty good, I think you had an impact on us the last time around, particularly on this subject, so I appreciate your input.

MR. LEE: Good morning, Commissioner Geesman, Commissioner Boyd, and esteemed members of the committee. My name is Vitaly Lee. I'm the Director of Commercial and Regulatory Affairs for AES Southland Company that operates three of the power plants that were initially subjected to this study, AES Huntington Beach, AES Redondo Beach, AES Alamitos.

The output of this power plants is contracted out under a long term agreement with a third party. Commissioner Geesman, the last time

I was offered the podium, I made a statement that the deep cycling on the units hurts the efficiency and the equipment itself, the reliability. You asked me whether Huntington Beach 3 and 4, the units that came on line in the last 18 months are being dispatched in the same manner. I didn't have the answer.

My answer to you is that they are being dispatched in the same manner, and I will make one general comment, though, that California ISO in the recent past has become cognoscente of this issue.

The ISO chooses to park the units at minimum load under recent waiver versus starting up and shutting them down within a matter of hours or days in the past.

To get back to this study, I would like to compliment the staff on this enormous effort. A lot of analysis went into this. I will just make brief comments I have, a few general comments, and then I have five specific comments to make.

The general comments are that if I were to summarize the results of this study, aging power plants play a vital role and will continue playing that role in the supply of energy in California. In the years to come, aging power plants are for the most BACT compliant or becoming BACT compliant. Hence, they are no worse than the new generation.

Even though the heat rate on these units is a little higher than the new generation, the load following capabilities make up for more than enough to compensate for that difference.

There are no technical or operational reasons why these units will not be able to continue to reliably supply power in the years to come. Having RMR a long term contracts in fully functionally capacity market will help extend their life and reliable operation of these units.

We concur with all of those conclusions presented by the staff. Furthermore, I will join my colleague, Greg Blue, and say that we support the idea that this state needs to create incentives to expedite the repowering of these units. We think that SB 1776 carried by Senate Bowen signed into law a couple of days ago by Governor Schwarzenegger is the right step in this direction.

The five specific comments that I have

are as noted by the staff in this draft paper, AES has opted out of this study because the staff put us on the low probability of retirement scale. As such, we did not provide quantitative data to staff. As such, I just want to go on record that we cannot claim responsibility for the accuracy of the data that staff presented in this part as it pertains to AES units.

The same comment applies to the staff's calculation of annual fixed revenue requirement on units Alamitos 1, 2, 4, 5, and 6 on page 35 because these units are not RMR units.

Average heat rate representation on AES units on page 32 is inaccurate.

On page 49, the staff talks about the data on forced outage and reliability analysis of these units are outdated and old and how probably there should be some new requirement imposed on the generators to supply this data.

My comment is that California ISO actually does have this data through there outage coordination protocol. The last thing our controller and operators need is basically a new obligation to supply this data so you can use that data.

Finally, there are some inconsistencies and discrepancies in this report. For example, 104 purports AES Alamitos and AES Huntington Beach are located in low income -- I'm sorry, there is substantial population of low income people of color surrounding AES Alamitos and AES Huntington Beach, yet on page 99, the staff states that Alamitos is located in one of Long Beach's most affluent regions. So, there is a discrepancy there.

Those of us who are familiar with housing in Orange County, Huntington Beach is not your typical low income community.

In conclusion, let me state that AES stands ready to continue our involvement in fostering a fair transparent market to supply the future energy needs. I thank you for your time.

PRESIDING MEMBER GEESMAN: Thank you very much. Questions?

MR. CARLSON: Good morning. Thanks for having us here again. I appreciate the opportunity to speak the Committee. In particular, I want to express our company's gratitude to the staff here at the Energy Commission and the work that they have done in this report.

There is a lot of work that has been done. They have met with a lot of different people in different agencies, and our company believes they have done a great job pulling it all together in something less than normal a boat load of paper. Succinctly stated, the importance of these aging power plants in several respects, not the least of which is electric system reliability here in California.

My name is Trent Carlson. I work at Reliant Energy. I am the Director of Asset Commercialization there. I've brought two other gentlemen with me, Roy Craft and Robert Lawhn. Our intention is to participate later today in the other portions of the meeting and provide specific comments and to answer any specific questions the staff or the committee may have.

I will keep our comments real brief in this opening here. I think very important to the findings that the Energy Commission staff has put out here is that there is 8,000 MW of capacity at risk. That is 8,000 MW of reliable capacity that is put at risk for several reasons.

I want to highlight at least one of them has to do with an unstable market design, an unstable market design that flows from some regulatory uncertainty. Greg Blue from Dynegy showed a simple chart of the impact of losing 8,000 MW in total simultaneously against simultaneous peak demand for electricity. That is probably a low probability event as Greg pointed out.

However, I wanted to pick up on that idea just briefly here in our opening comments. To point out the fact that one unit or one plant or as few as two plants if unable would have put California in a very different situation this summer, even though we did not have the hot summer that was forecasted as the high load case.

The combination that exist in the transmission system that cannot be foreseen a year in advance or sometimes even two years in advance really need to be respected. This finding that the Commission staff is making that there are 8,000 MW at risk should not be under emphasized. That needs to be taken beyond the Commission here and shared with the sister agencies and others in the legislature.

We also appreciate that the result of

the staff's work has explained that these aging power plants are not dirty. They are really not all that less efficient. In fact, looking at it in terms of emissions, we've supplied comments that if the Commission staff were to do a comparison of the aging power plant technologies to the newer combined cycle plants and take into account the emissions from start up and shut down, they would be even closer matched.

The study touches on that, it doesn't emphasize it. We are encouraged by the analysis that has been done and the findings put forth in the report. We just think they could be emphasized a little bit more.

We really believe that this report sends a clear message regarding the value and reliability benefit of California's aging power plants. We believe that should be, again, emphasized in the report however possible. The results of this report needs to be shared with the sister agencies now, in fact, before the issue of the final report or any follow on study work. We believe that no additional data can be provided to the Energy Commission that will materially effect that finding.

Just this morning, briefly I want to touch on two areas that we believe are very important to clarify in the report to the extent there's any supplement issue beyond what we have in hand today.

That is, the report indicates that the capacity that may be lost due to aging plant retirements will likely be replaced by a variety of sources including demand side management, new renewable energy projects, increased generation in the existing power plants, new power plants, or transmission upgrades.

Just to be very clear, Reliant is not adverse to any of these technologies or alternative supplies of capacity or energy. In fact, we have loads acting as resources in other regions, and we are very supportive of renewable projects and trading of renewable energy credits in other regions of the country.

What we would like to see the report clarify is that few of these alternatives can be deployed within the study period, that is the study period 2004 through 2008. On a MW scale equivalent to the size of aging plants that are subject to high or medium risk of retirement and in the locations required to maintain local area reliability with the equivalent flexibility of capacity commitment and energy dispatch and an all end equivalent cost of capacity and energy.

We believe that is a very important clarification because we would not want anyone to misread what we understand to be conclusion of the report as to the importance of these power plants and the seriousness at which the 8,000 MW is at risk and possibly a good share of it not replaceable with these other alternatives during the study period.

Finally, I wanted to leave the committee with comments that we started with in our last meeting, and that has to do with the market design. I refer to it as the unstable market design, and it is a market design that in our opinion does not need to persist until 2007 or the succeeding or successor market redesign of MDO 2 or MRTU or whatever it may be called between now and 2007.

In fact, there are several key elements that can be fixed now and should be fixed now to assure that the 8,000 MW of reliable capacity that is potentially at risk for retirement is not retired because of the unstable market design. Those elements include the must offer waiver denial process. It must go away now. It must be replaced with a contracting mechanism to compensate the owners of the resources for that capacity. That is just an absolute must. Without that and with the risk of retirement, the summer of 2004, if we had just the same summer in 2005, we have a different picture if some or several of these aging power plants actually retire.

Then there is the reliability must run criteria. For whatever reason, the CAL ISO has chosen not to update that criteria so as to select generating units required for reliability services. Just last week they announced the designations for year 2005. Several of the plants that the Energy Commission's study identified as required for reliability are missing from the designations.

We think that is important and timely as to any supplement that the Energy Commission staff might issue in the future to reflect the current status of RMR selections for 2005.

Of late, since we last met, Reliant and CAL ISO worked together to bring Etiwanda back on line to address reliability problems this summer. As of bringing one of those units back on line, we found another serious problem that will challenge all of the 18 power plants. That is the California ISO's implementation of its tariff to replace market-based bids of ancillary service capacity with RMR capacity from condition 2 units.

There are not many people that I have found that were aware of this problem. In fact, our folks that trade electricity day to day were unaware of the reason why the market for ancillary service capacity would diminish on peak, and actually at times, be higher priced off peak.

When we brought on Etiwanda Unit 4 on July 6 of this year, we found out how CAL ISO was implementing the tariff in this respect. In fact, they are not utilizing RMR capacity as and when required to maintain the reliability of the ISO-controlled grid, but instead are using the RMR capacity to replace market-paced bids.

Therefore, when we bring our plant on line and in accordance with the contract, we bid the uncommitted capacity into the next available market, the ISO, instead of using it as and when required, uses it to replace market-paced bids, and there in turn, many days, almost on a daily basis, the ancillary service capacity market is collapsed in most hours.

We just want to bring that to the Committee's attention. We believe there is a supplement. We would like to see that highlighted, and we would enjoy answering any questions that you might have on this particular subject that has been brought to our attention since July 6.

There is also hard wired mitigation procedures that are written into the California ISO's tariff. We are not looking to the Committee to file a complaint at FERC to get these hard coated numbers removed from the tariff, but we would sincerely appreciate this committee's and the weight of this committee and the weight of the technical analysis that it's Commission staff can provide to opine on some of these hard wired mitigation procedures that are currently being enforced in California.

We believe that there is appropriate mitigation that must be applied, in particular in local areas so that market power is not a concern. That it can't be generally applied such that at any time any one submits a bid, whether it is called "in sequence" within the market our "out of sequence" and it is priced at more than $91.87, that all of the bids in all regions of the California ISO are mitigated to reference levels. Absent a reference level being able to calculated at the time to a default level.

We think this is a serious matter. We are not asking that all the price caps be lifted to be very clear. We are just wanting this committee to give indication that mitigation procedures should reflect changing market conditions. They should not be hard coated into a regulatory document that reflects a relic of an event that occurred several years past.

Finally, and I hope our company is not going to offend anyone with this last comment, but it is our opinion that there is an ineffective commitment to resource adequacy at this time in California.

Not to dwell on all of the reasons why we believe it is ineffective, but we still have conversations where folks are debating whether resource adequacy should be assured now, 2006, or 2008. We believe it needs to be assured now.

Also, the CPUC in its January rule is requiring utilities to prove up 90 percent of the capacity that they will make available in an upcoming summer season. Not 100 percent resource adequacy, that is not the policy. The policy is to prove up 90 percent of the contracts available for the forecasted conditions in the upcoming summer.

Worse yet, instead of those compliance showings occurring a year or two in advance, they may only occur six to seven months in advance of the upcoming summer season, leaving little to no time to react.

With that, I'll conclude my comments. I'll take any questions or make myself and my colleagues available later in the panels. Again, I appreciate the opportunity.

PRESIDING MEMBER GEESMAN: Thanks Trent. You had mentioned your view that the aging plants have value in bolstering against problems in the transmission system that cannot be foreseen one year ahead or perhaps two years ahead. I wonder if you would expand on your thoughts on that.

MR. CARLSON: Certainly. The best and most recent example of magnitude is the derate of the pacific DC inter tie that is nominally rated for 3,100 MW. Throughout a good portion of this year, it has been derated to something like two-thirds or a third of its capability.

In fourth quarter, it will be I think completed derated to zero. That had a little bit of lead time, and so there was time to react to that. Not time enough to build a plant that would replace the generating units that were called upon and being called upon as I stand here and speak before this committee to respond to that derate.

There are other things that cannot be foreseen. For example, you can't forecast hydro-electric power perfectly. If this were a strictly thermal system where you didn't have to worry about hydro-electric generation as part of the mix, it probably wouldn't be that big of deal, but in California, with its Northern California hydro and Southern California Big Creek Project and its dependence on northwest hydro-electric imports, there is enough swing in that alone that if you don't assure resource adequacy, the bottom can fall out of that with about the ease of meteorologists guessing wrong.

Finally, there's the typical forest

fires which seem to be plaguing us every year, ever year, ever since I've lived here fifteen years ago. Short of solving that problem, which I wish we could, that also creates uncertainty. If these power plants were not here during some of these most recent fires, or I will just say many of the fires over the course of the last several years, we would have been in a world of hurt.

PRESIDING MEMBER GEESMAN: You also said that in this last RMR cycle, the ISO had not changed its criteria. What types of changes do you think it should have made?

MR. CARLSON: I believe, and I've been criticized for this, and I'm not sure how much of this is company policy at this time, but I have a little bit of operations experience, and when I into a short term problem that must be solved, I look at the historic data that I have. I look at my short term forecast, and I see what transmission is going to be built or may not be built, what type of generation is going to available or not. I don't have to run a lot of studies, I just have to look at my operating data, and I look at which units are being committed routinely to maintain grid reliability. I start there first.

The criteria should reflect -- forget criteria, forget what the planners came up with in a committee or some other deliberative process over the course of years. If the power system required capacity in a particular location, whether it be for a local reason, an intra-zonal reason, a regional reason, or some other poorly defined basis, if it is just needed to make sure that you have adequate capacity where you need it to avoid transmission line overloads, the criteria should be crystal clear and the result of the evaluation well understood. Those power plants should be contracted.

I believe that the ISO goes into many days putting itself unnecessarily at risk because it has not contracted for the resources that it knows it is going to need several months in advance.

PRESIDING MEMBER GEESMAN: Other questions for Trent?

(No response.)

PRESIDING MEMBER GEESMAN: Thank you very much.

MR. CARLSON: Thank you.

MR. TRASK: For folks listening in on the web, it turns out we weren't able to use the telephone number that we had posted for folks to call in and give us their comments. I am going to give out a new number right now. It is 888-390-8784. I'll repeat that, 888-390-8784, and then at the prompt you will want to put in a code, which is 21142, which I believe is the same as the code that was in the notice.

I'll repeat that in a little bit later on. If you folks who are listening on the web would like to give a comment, go ahead and call in on that number.

At this point, unless there is any more general comments or presentations --

PRESIDING MEMBER GEESMAN: I had a form from Steven Goschke at Duke.

MR. GOSCHKE: Good morning, Commissioners, how are you? My name is Steve Goschke, I'm a power plant manager at Morrow Bay, one of the aging facilities that is featured predominantly in the report, down in the south of Path 15 Basin. I don't have some of the same attributes that some of those facilities up there are in the Bay Area, but I came today to participate in the workshop. Being a plant manager, hopefully I can contribute some field level insight into what is going on, at least at our power plant.

A little bit of background. My power plant is a 49 year old facility. It is 1002 net MW. It is all natural gas fired at this point. It's got four units. It is located in Morro Bay on the central coast.

A couple of years ago we were running it at 60 percent capacity factor. The last year and a half, it's been less than five percent. This year we are currently sitting at four percent. So, a big change in the California market and a big impact on a business like mine that is totally merchant related.

As such, being a merchant facility, we are continually looking at the economics of keeping the place open. We are continuing to do that, and we will be doing that seriously as we get into the fall long path the run season this year.

Some of the things that occur in hurdles that Morro Bay has ahead of it include renewal of an out fall easement with the city. We've got a

50 year permit when the facility that was first put in place to use the out fall for our discharge of ocean water cooling, and that comes up for renewal with the City of Morro Bay on the 15th of November, a very critical day in the life of the power plant.

Our estimates are that could cost us an extra four million dollars and kind of adds to the negative economics of running that particular facility. We are also in the process of getting a new NPDS permit for that facility. Again, those hearings will be head towards the end of this year. It is another potential cost adder to the running of the Morro Bay power plant.

Right now we don't have a contract for the out put of the facility. We do get called on the ISO frequently underneath must offer waivers, which again is not necessarily a money making proposition for us.

We don't have a RMR contract. We would be willing to keep the place open if we got an RMR contract. We continue to go out and are pounding the pavement daily trying to find someone to buy the output of the power plant. If this sounds a little bit like a sales pitch, I'm not the marketing guy, but if you know anybody that wants the output, give me a call. I'd be glad to talk to them.

I guess the report was interesting to me. I thought the staff did a good job. Like a lot of others that spoke, gathered a lot of critical information and certainly have said many times in the report that the threat to reliability from retirement shouldn't be underestimated.

Again, my facility is 1,002 MW. October 13 of last year I put Units 1 and 2 in an inactive status, is it retirement, is it mothball. Here I am throwing out another term for you to wrestle with, but basically what that means is I took those two units off the PGA Schedule 1 and the ISO no longer calls on those as must offer facilities. There is a mechanism for doing that.

I think the report needs to add a little emphasis to address the impact of the regulatory uncertainty related to the wholesale market structure and procurement policies. As long as the structure markets are in transition and disarray, major capital investment is unlikely, except on a project financing based on bi-lateral contracting.

The Energy Commission did recently approve repowering of Morro Bay power plant, which I thank you very much. It has been a long process getting that done, and certainly breathes some life back into my facility. The employees were walking around a couple of days with a high fives and still realizing there is a few permits to get through, but that was certainly a big step in the long term vision of what many of us have for that facility.

We have had a tough time at the power plant over the last couple of years. I think two or three years ago, we had almost 90 employees there, we are down to 30. A bunch of hard working people. We had 24 start ups, successful start ups so far this year, with the reduced staff and the aging equipment. You know, a little bit of luck, a lot of hard work, which is keeping this plant's head barely above water. There is a lot of things stacking up against it that are coming down the pipe that still need to be overcome.

I just wanted to be here today to try to talk to you about some of those things and let you know about the incremental cost increases that we are starting to see that maybe other plant people are starting to see, things like SER, though not a requirement in our particular air basin at this particular time, you know, those kinds of $15 million capital additions to our facility certainly would impact or factor in to our decisions about what we do with the future of those units.

I guess like many have mentioned, some sort of short term capacity market structure now, just to get us by this interim period, I think as many that have spoken here today, the electric grid in California is very complicated. As you can see with MDO 2 and some of the load pocket stuff, we are just now starting to come to some understanding of how complicated it is and how much trouble it is.

I think there's going to be a little bit of a road to go through to kind of work ourselves through this having some sort of short term capacity marker or whatever to buy us some time to figure that out seems to make a lot of sense to me.

I guess I would just like to close by saying we will be seriously evaluating Morro Bay's future here this fall. We are all continually looking for ways to keep the plant open. We think it is a very good plant, a well maintained plant, and can serve the needs of California for many years if it is continued to do that financially.

I guess I'd also like to say that we submitted a bunch of written comments that are more specific line by line, chapter by chapter to the study that we can go through in more detail during the break out sessions. With that, I will close unless there are any questions for me. Otherwise, I will talk to you this afternoon.

PRESIDING MEMBER GEESMAN: Thank you very much, Steve.

MR. GOSCHKE: Thank you.

MR. TRASK: This is where I get to say we continue to have technical difficulties, please stand by. It turns out the telephone number that I gave out just a little bit ago goes to a doctor's office, so maybe you can make an appointment. Because we are having difficulty with our phone system, we are encouraging people to send in their comments by e-mail right now. These could be in the form of a questions as well that we can get to during our focus discussions. The e-mail address, again, is IEPRhearing, that is one word, I-E-P-R-h-e-a-r-i-n-g@energy.state.ca.us. Any further general comments or presentations from the audience?

MR. MOBASHERI: My name is Fred Mobasheri. I'm a consultant with the Electric Power Group. There have been several references to repowering, and my question is really repowering is not defined. Some people use repowering as changing the steam units for combined cycle. That was the original repower that was in the 70's and 80's discussed.

Some people use it like the Los Angeles Department of Water and Power use it to shut down existing plants and build a completely new plant at the same site and they call it repowering.

Some people just investing on the new existing power plant, they call it repower. So, it is very difficult, so I would really suggest that if some people are using repowering they should define what they mean by repower.

When I was at Southern California Edison, we seriously looked at repower meaning converting steam units to combined cycles. They were not economic at that time, this was in the 80's. Many places, especially from the coastal plants, there is not enough space to put the new combined cycle. There is a lot of resistance locally to convert these to new combined cycle because the cities around them they think that these units are going to die and go away.

It is not going to be very easy to build new power plants there. So, the question is really if you want to keep these existing units alive and you need them because of the contingency that was discussed like transmission contingency, the weather, the hydro, you need these power plants for contingency.

At the same time, utilities don't feel that they have an obligation to meet these contingencies. In the old days before deregulation, this was a commitment on their part that they have to keep these units because of the contingency, but I don't think at the present time that the utilities are really looking at the contingency.

If you look at their findings at the PUC, there is a significant amount of need that they show, the three utilities they are showing a significant amount of need in the next few years. At the same time, there is no real commitment to go to the market and buy any power from old aging plants. So, I am also concerned that this 8,000 MW will be at risk as the gentleman from Morro Bay was saying. You can't keep these units at 5 percent capacity and pay for several million dollars of relicensing or whatever the new costs are.

Thank you.

PRESIDING MEMBER GEESMAN: Thank you, Fred.

MR. TRASK: At this point, we are scheduled to go into our more focused discussions. We had in the agenda four topics. I think we will probably shift and just rather to focus on the four chapters, Chapters 2, 3, 4, 5, and 6. That would be five chapters. It's a little after 11:00. Would folks like to take a break before we go into discussion?

(No response.)

MR. TRASK: I suggest we get right into it. By the way, for folks listening in on the web, we did manage to get our presentation up on the website. Also on the website are the agenda and the set of questions that we have put out to folks. They are in the way of general questions, and we have some specific questions. You can call those up on your screen too from the IEPR website.

Why don't we start with Chapter 2, which is where we discussed the role of the aging power plants.

PRESIDING MEMBER GEESMAN: You know, Matt, maybe we can make use of all this furniture up here and invite people who expect to comment on these to come up and take these chairs. It might be easier to communicate.

MR. TRASK: As long as we can get the microphones to work. Virtually, anybody who would like to participate, I would invite staff as well, to come on up and have a seat in the we are calling it the UN pit where the interpreters usually sit I guess.

I'll shift over here where I can face everybody at once. We will just open it up to general comments. The first one is did we accurately describe the role of aging plants.

It turns out what we hope now is the correct number to call in. It is 888-390-0784, 888-390-0784. When you get the prompt, you plug in the code 21142.

Would any of our parties like to start

just commenting on the factual accuracy of what we have in Chapter 2.

PRESIDING MEMBER GEESMAN: There is not a need to repeat any of the general comments that were made earlier. We have picked those up on our record.

MR. GULIASI: Thank you, Matt. Actually I have it on a good source that the doctor's office that you gave the number for is actually a gerontologist. I think some of the people put him to good use.

MR. TRASK: I may need him.

MR. GULIASI: Good morning, I am Les Guliasi from Pacific Gas and Electric Company. I just want to say as a general matter that we have participated in this part of the proceeding through our attendance at the various workshops, and we have provided information to the staff including responses to previous data requests.

The remarks that I am going to make today which are basically focused on a few specific questions will be followed by written responses to the questions that the staff posed for us.

As a general matter, we are interested

in this subject for two major reasons. First of all, we are still the owner of two of the aging, I might say elderly, power plants on the list, Humboldt Bay power plants and the Hunters Point power plant. I certainly, having heard the presentations this morning, don't envy the position of the owners of the other aging power plants in the State of California.

At one point, we were the owners of some of these power plants, and I now see that they are faced with the very tough business economic decisions that we would otherwise have been faced with, and it is not an enviable position for them to be in.

The second reason that we are interested, besides being the owner of some of these plants, is that as a load serving entity, we have a responsibility to insure that our customers receive reliable service. So, the future and the fate of these power plants is really a big concern to us as we try to fill our obligations to insure that our customers receive reliable and economic service from my company.

What we have done is really focus on the various questions that the staff posed for us. I just want to try to provide some response now through my oral remarks. As I said, we will follow up with more detailed written comments that I hope the staff will find useful in rounding out their report.

The first question had to do with the filing you made at the Public Utilities Commission about our long-term resource plan. Some of the assumptions contained in our resource plan and specifically about some of the assumptions we made with respect to reliability must run units. Those are really questions, 2(c) and 2(d), for PG & E.

Just as a general matter, the assumptions that we made about reliability must run contracts is consistent with the pronouncements we have heard both from the California Public Utilities Commission and from the California ISO that reliance on reliability must run contracts should be reduced.

The Commission and decision 0401050 has stated that position and very recently in procurement proceedings, the California ISO's witness Pettingil has made a similar pronouncement. We will provide references to those documents when we submit written comments.

In our December 2003 grid expansion plan that we submitted to the ISO, we proposed several transmission reinforcements that are designed specifically to lesson reliance on reliability must run contracts. I can point you to Table 4.1 of that plan. We expect many of these transmission upgrades to be in service in the time frame that would help us rely less on reliability must run contracts. Many of these transmission reinforcements have been approved recently by the California ISO.

Let me just say further that when we soon issue requests for offers in our procurement proceedings or procurement plan, we will be asking for various products, whether they are short term or medium term contracts for capacity for peaking service, or for load shaping services. We are hoping that the offers we get will meet our resource needs and further enable us to rely less on reliability must run contracts. We are sort of in a wait and see position.

Just let me add, I can appreciate the position that the current power plant owners are in. Not knowing what will happen. We do have certain requirements from the Public Utilities

Commission to insure we have reliable resources to meet our needs.

We hope that the auction process will prove that a competitive market can work, and we hope that not only we get what we need to meet our obligations, but we hope that through that competitive bidding process, California as a whole will learn something from the process, and we can move forward as one small perhaps building block toward a clearer market design.

Moving now to question (d). Again that question focused more specifically on RMR. Just to explain the analysis a little bit. We didn't assume which specific units would retire when we filed our long term plan. We considered that there is more than 4,500 MW of aging power plant availability connected to our system. We assume that at least 2,000 MW of that 4,500 or so MW would retire by the year 2010 if those plants were not offered a contractual commitment to allow them to maintain or to upgrade their facilities.

We have some evidence, though, that some of the assumptions we made were valid. At your June 9 workshop in this proceeding, I believe someone from Mirant indicated that Contra Costa

Unit 6 and Pittsburg Unit 7 which make up over 1,000 MW of power combined would retire without RMR contracts.

Additionally, we've heard from the California ISO through their local area reliability services recommendations that these assumptions that we made are reasonable. Under some of the scenarios that the ISO looked at, Pittsburg 7 does not have or will not have an RMR contract. Under another set of scenarios, Pittsburg 6, which has 325 MW will not have a contract either.

Contra Costa Unit 6 won't have a contract under any of the possible scenarios run by the ISO. Even though some of these units have SER equipment installed and they will be able to run their heat rates as others have mentioned are rather high. Those kinds of considerations may factor in to future analysis.

Again, I want to bring into the picture, and I will get into this a little bit later, some of the transmission upgrades that we proposed and some of those that have been approved by the ISO may lead to further reliance or less reliance, excuse me, on RMR contracts.

Now, those are some of the factors or forces kind of pushing in one direction, but of course there are forces pushing in the other direction. It may be that some of these power plants might be able to secure short run or medium run contracts.

Some of the contractual commitments that they may be looking for from us as we move forward with our request for offers as part of our long term resource plant filing at the PUC. If some of these power plants actually win some bids, then you would see some postponement of retirements.

Thank you, that concludes what I have to say about the set of questions No. 2 and turn it over to the next person.

MS. JONES: Les, can I ask you a question about your 2003 grid expansion plan? Did you have dates, on line dates identified in the plan?

MR. GULIASI: I'm not very familiar with the specifics of the plan, but I believe there are time frames associated with each of the transmission projects and transmission upgrades. I think if someone is here from the ISO who may be more familiar with that information can comment, but I believe there are time frames.

MS. JONES: Maybe in your written comments, if you could address how those are progressing, whether you expect them to be on line. We are interested in mostly in the near term time frame of the study between now and 2008.

MR. GULIASI: Okay.

MS. JONES: Thanks.

PRESIDING MEMBER GEESMAN: Why have the RMR contracts persisted so long in your service territory? Edison was able to reduce them pretty substantially in their service territory, why haven't you?

MR. GULIASI: I am not actually sure about why they have persisted. I am just guessing here, I'm a little bit outside of my comfort zone, with the amount of knowledge I have about that, but it may be associated with the transmission upgrades and the transmission reinforcements that would be used as sort of the substitute for the reliance on must run contracts. It may have just taken a longer period of time for us to kind of move through that process. That is subject to check. In fact, I can find out.

PRESIDING MEMBER GEESMAN: If you could

include some addressing that in your written comments. I guess what I am driving at is what has changed now. Obviously, you have come out of bankruptcy, but is there something else that reflects a change on the part of your company's planning process that would cause you now to make an indication that you don't anticipate any RMR contracts after 2006?

MR. GULIASI: Again, I think the proof is in the pudding, and we will have to see what happens through the competitive bidding process. To the extent that we can find attractive prices and the right kinds of services being bid, we would take those offers. I think that would help us rely less on the reliability must run contracts.

PRESIDING MEMBER GEESMAN: Okay.

MR. WEISENMULLER: Hi Les, this is Bob Weisenmuller. I just had a follow up question. On the transmission expansion planning, and I realize you may need to do this in the written comments, what sort of cost effectiveness criteria were you using looking at whether or not to do a transmission expansion or to continue a RMR contract?

MR. GULIASI: That's a good question, Bob. I don't know what the specific cost benefit analysis was, but we will look into that, and we can provide some written response that might help the staff.

MR. WEISENMULLER: All right. That would be good.

MR. TRASK: Any other comments on that particular issue.

MS. THOMAS: On No. 2? I'm Mary Jo Thomas with the California ISO. Question No. 2(b) are the staff's assumptions about municipal and RMR unit retirement risk accurate? I provided some written comments, but it is not exactly accurate in the fact that the CEC comments should reflect that while a RMR contract provides some stability for RMR units in itself, a RMR contract does not guarantee the longevity of a given power plant.

The contracts are renewed on an annual basis based on new generation, load growth, and transmission projects in those areas. Each year we carefully review each generator and they may or may not make the list as has been pointed out that we are looking at Contra Costa or Pittsburg 6 and

7 and those units potentially not making that list this year. It is not ruled out that they will or will not at this point.

In the RMR contracts, because they are only on an annual basis, they don't guarantee sufficient -- or the RMR process is not sufficient to insure that the needed capacity will remain to serve the overall system load, and it doesn't provide adequate cost recovery of capital costs for projects that have multiple year annuities.

If a generator loses its contracts and then decides that they can't operate and would need to retire the unit, there's some provisions where they wouldn't be able to collect all of the capital cost that has annuities attached to it.

We did provide some clarification there and would like that the CEC add some comments regarding the fact that a RMR contract doesn't guarantee that a generator will remain in service.

MR. TRASK: Thank you, Mary Jo. The staff -- our conclusion was that if the RMR contract was lost, was not renewed, that would increase the possibility of retirement. I think it is interesting that Greg it sounded like you were saying that a plant could retire even while it holds an RMR contract.

MR. BLUE: No, not during the term of the contract.

MR. TRASK: Right. As far as our rankings of high, medium, and low, it was only after a unit lost that contract that we accelerated or raised the risk of retirement.

MS. JONES: We've also provided some recommendations to move some of the generators into a high priority list because of new transmission projects that would be going in those areas or new generators that may potentially cause these units to be a high risk. So, those are in our comments as well.

PRESIDING MEMBER GEESMAN: Let me ask you, Mary Jo, the same question I asked Les, but I guess expanded a bit to pick up all of the RMR contracts. Why, in your opinion, have they persisted so long?

MS. THOMAS: I don't know if I am exactly qualified either to answer that question, but I could probably get a good answer for you. I think just from the hearsay that I hear over the cubicle walls at the ISO part of it has to do with a lot of resistance to building new generation from the community and new transmission from the community.

PRESIDING MEMBER GEESMAN: I guess to try and pare that down a bit, I am assuming that has a very heave locational aspect to it. I am fairly familiar on the generation side because we either we see a power plant application or we don't.

On the transmission side, while people have focused quite a bit on the larger projects that require CPCN's, I've got a nagging sense that on the small upgrades that go through the GO 131 D process and which at least to date there's not been much criticism of that process, whether the local reliability analysis is properly stimulating those investments. Whether we aren't underinvesting in transmission upgrades and end up resorting to reliance on RMR contracts which nobody appears to like.

The contracting party will begrudgingly accept as the only way he can stay operating another year, but both the Public Utilities Commission and the ISO have been pretty direct in stating we ought to be getting off of these.

My frustration is it doesn't appear to

me, other than PG & E's hopes in its long term resource filing, that we clearly are getting off them. They seem to persist.

MS. THOMAS: Of course, the ISO does -- we also would prefer that PG & E pick up the RMR contracts through the resource adequacy requirement, and we have provided testimony. Phil Pettingil has provided testimony in that the investor owned utilities are in a better position because they -- we can only look at these on an annual basis, where they can look at something in a more longer term.

In a longer term basis, they can make a decision of building new generation versus a long term investment in an existing generator. I think that would probably resolve some of those problems if there is a local reliability requirement in the resource adequacy requirements.

PRESIDING MEMBER GEESMAN: I guess my question is how much responsibility would you shift to them. The resource adequacy process seem fairly burdened now with pretty large number of expectations on the part of a variety of people. For the last five or six years, the state has looked to the ISO to provide assurances of local reliability. Would you transfer all of that responsibility to the LSE's?

MS. THOMAS: I will get you an answer, okay.

MR. GULIASI: Commissioner Geesman, may I add to this a little bit more? I think it is very helpful that you sort of parceled this out a little bit in terms of transmission and you look at what the utilities do kind of on a routine basis through as you referenced the G 01 31 D process versus the kind of bigger projects that get more scrutiny and analysis and careful consideration of the ISO. Beyond that, we have the trade offs between generation and transmission.

Just one word of caution here. You sort of hypothesized that perhaps the utilities may not be investing enough in transmission projects through the kind of routine G0131 D process. We can analyze that, but in my experience having gone through PUC processes, rate case proceedings where that subject is looked at very carefully, others hypothesize the opposite, that is, that we invest, not only we, PG & E, but I think the utilities tend to invest too much in their transmission and distribution systems.

We get accused of gold-plating our systems for lots of reasons. Some people think that we gold-plate the systems because we invest money, it goes into a rate base we earn.

The engineers will tell you that they invest what is adequate to insure that the system runs properly. There is a lot of debate there. I think I can say confidently that we believe that we don't gold-plate our system and invest too much, but I guess the question becomes then how much does the ISO take into account those kinds of routine investments in the system.

Are they accounted for enough? I would venture a guess that through the ISO's conservative approach, not enough credit is given to those kinds of reinforcements, even though the data are provided, the information is given, then I think that they are not -- again, it is a guess, hypothesis, that they are not valuing those kinds of investments and upgrades sufficiently leading to a more conservative outcome that would -- you know, getting back to your initial question, lead to a decision to enable those RMR contracts to persist.

PRESIDING MEMBER GEESMAN: Let me first say that as I think you know, for the last couple of years, this Commission I think has been quite clear in expressing its concern that there is an asymmetric risk as it relates to investment of the transmission system. The risk is of underinvestment, not of over investment.

I think our history as a state over the course of the last decade or perhaps two that would suggest that gold-plating the transmission is a bit of a false boogie man. Having said that, the persistence of congestion in my mind raises questions as to whether or not the utilities aren't under investing. I understand that the RMR process is a reliability focused process, so you can't expect it to render results that it would eliminate all economic congestion.

I also understand it is a fair amount of what they characterize as institutional congestion that appears just given the way in which we operate the system. It is not physically real.

In Southern California this year, we've been on the verge several times of reliability problems caused by congestion or limitations on our ability to import. That translates to me as a policy maker, as a very pertinent symptom of a underinvestment problem. I am trying to determine what can we adjust in our planning and investment review decision making that will correct that and correct that in a timely way.

I recognize it is a bit afield from this question of addressing problems that confront the aging plants, but to the extent that it involves the RMR contracts and the RMR process, I think it is central.

Trent?

MR. CARLSON: Yes, Commissioner Geesman, I'd like to add to that. Earlier you asked the question how much responsibility should the CAL ISO shift to the utilities, and I don't know what that answer is either, but I believe you are hitting on something. That is, what policy would the Commission adopt or the agencies adopt who would get transmission built when and where it is needed and power plants sited when and where they are needed.

The Commission and sister agencies could adopt policies in an attempt to enforce them. What we are trying to bring to this draft report and what we would like to see reflected and emphasized is that even if the Commission were to adopt a policy in an attempt to enforce it, at the present time lacking any changes in the near term during the study period to the market design you would be running counter to the incentives created.

For example, the must offer waiver denial. Now RMR is not perfect. It is not something you go to a bank and say I want to go build a unit because I can get a RMR contract from year to year obviously, but at least the cost allocation is appropriate.

The cost allocation is to the transmission owner in whose service territory the RMR unit is located. To this point, when a unit is denied a must offer waiver request, the cost of starting up that unit, running it at minimum load at the least economic part of its operating curve, that is uplifted to the entire market on a load ratio share basis, which tells the transmission company just the opposite what you would adopt this policy to get a transmission line built there or generator built there.

Our point is, (a) we agree with you, there needs to be policy that is clear. We have hear statements previously that maybe the transmission siting should be a little bit more qualitative than quantitative. We are fully on board with that here, and which I wish would catch on across the United States, in fact, but we have to have the market design running at least some what in parallel. It cannot be running orthogonal or 180 degrees out from any beneficial policy that this Commission might adopt.

Right now they are at least orthogonal, and in many respects 180 degrees out from what I believe this Commission is intending to accomplish by way of this current evaluation of aging power plants. Thank you.

PRESIDING MEMBER GEESMAN: Greg.

MR. BLUE: Commissioner Geesman, first of all, I want to thoroughly endorse Trent's comments. Bottom line, the must offer process is allowing Edison to get free capacity and passing on part of that cost to Les here. I am sure they are not happy about that either. It is a big issue. That is what they call a perverse incentive where Edison is not incentivized to contract. RMR's could go away tomorrow if they would sign up the contracts they need.

Getting back to one of your earlier questions, and I am going to get to a couple of quick answers here in just one second, but you also asked why does Edison not have RMR and PG & E still does.

Early on in the ISO process, I think this happened after the first year of RMR, Edison was able working with the staff, convince the staff at the ISO to actually change the RMR criteria. I don't have the exact change, but they made a change to some how in the criteria itself that allowed them to substitute the RMR plants with some condenser upgrades, which they have done.

Now, based on the situation in today's market, they really should be having RMR contracts, and right now they are not incentivized because they are getting what we determined as be free capacity. They are not paying for it. They just sit back. In their current procurement practices in today's market is they are buying power that can't be delivered to the load. Yes, there is congestion, but it is all part of the -- that could be fixed with enough upgrades to the transmission system, but it is not going to happen in this study period time. Just like in this four year time period.

I have a question for Les, are we allowed to kind of ask questions?

PRESIDING MEMBER GEESMAN: Yes, please.

MR. BLUE: Les, you had mentioned that PG & E is going to be putting out a RFO, and I am assuming that is after the final decision which could be now into next year based on the final PUC decision approving a long term plan?

MR. GULIASI: Right. The PUC decision we hope will come out at the end of this year. Like most PUC decisions doesn't meet the stated time frame, so this may be early next year. Obviously, we will be doing all the necessary planning to get those requests for offers out as soon as possible.

MR. BLUE: My point of that is we are still going to have a gap. We endorse PG & E's approach to going out and solving the problems. I think part of the issue over the last couple of years was that you had one entity responsible for liability, and then you had another entity responsible for paying for it. So, you had kind of a potentially not everybody being on the same page. Hopefully, that is going to be resolved here in the future if we can get there fast enough.

MR. GULIASI: How would you see that being resolved between the ISO and the LSE's as it relates to reliability?

MR. BLUE: I think when the resource adequacy requirements are in place, whatever deliverability standards are in place, that will put some requirement on load serving entities to buy in certain locations or to buy power that is deliverable, thereby alleviating the need for RMR contracts.

If they do some multi-year contracts in a certain area, that is how it is going to be relieved, through the PUC resource adequacy requirements. That is one of our comments to the whole resource adequacy requirements is that they have to be requirements and there has to be if they don't meet the requirements, there has got to be some consequence to that. That is all kind of fuzzy right now.

PRESIDING MEMBER GEESMAN: What is your level of satisfaction with the approach we are taking in the Edison service territory this summer?

MR. BLUE: You mean '04?

PRESIDING MEMBER GEESMAN: Yes.

MR. BLUE: Or '05?

PRESIDING MEMBER GEESMAN: '04.

MR. BLUE: In regards to what?

PRESIDING MEMBER GEESMAN: Local reliability.

MR. BLUE: They haven't done anything yet. There has been an order out, there's an order out.

PRESIDING MEMBER GEESMAN: They've been directed to do so.

MR. BLUE: They've been directed to. There's an advice letter that has kind of laid out a procedure, no procurements yet. It's August. We are expecting any day now another advice letter that actually puts it in a requirement to procure. We haven't seen it yet, so I can't comment until that actually happens. It is coming, they say it's coming.

PRESIDING MEMBER GEESMAN: Do you think that is a preferable direction to move in than continued reliance on the ISO's RMR structure?

MR. BLUE: It's a baby step in the right

direction. By getting the LSE's to actually procure in the load pocket versus the ISO. Nothing against the ISO, but I would rather do business with the utility.

MS. JONES: Let me ask you a question related to that. We've heard a lot of discussion about the load pockets, but the congestion appears to be a fairly transient and difficult to pin down phenomenon, and how do you specify resource adequacy requirements when you have such changing conditions on the system that adequately assure reliability?

MR. BLUE: I don't think I am qualified to answer that because I am not a transmission expert, and I haven't realized that the conditions were changing so drastically, I guess so rapidly. I don't have a good answer for you, but --

PRESIDING MEMBER GEESMAN: Let me ask those of you that care to address that in your written comment, try and reconcile that for our benefit with AB 57 and the ostensible commitment to not conduct retroactive reasonable reviews of utility procurement decisions.

If we are attempting to move in a prescriptive pro-active direction where the utilities receive their guidance from the state in advance, try and reconcile that with a rapidly changing local reliability consideration and whatever rules the regulatory system can impose on the utilities proactively.

MR. BLUE: We are going to file some supplemental comments anyway, so we will try to adjust that. I will say that it could be a situation where you actually you can never get rid of all the RMR. You can reduce RMR, but there potentially could be some situations where you need a certain plant or two at a location period. So, there might be a potential that you always need some RMR. I'm just speculating.

PRESIDING MEMBER GEESMAN: I guess the other aspect of that, Greg, that I have some concerns about is the extent to which transferring these responsibilities to the utilities ends up eroding the commitment or enforceability of a non-discriminatory open access to the transmission system, and whether you or any other plant owners who may in fact find yourselves competing with the utility on plant in the future, feel that kind of transfer is something that jeopardizes a hard won right of open access and non-discriminatory access.

MR. BLUE: We will put some thought to that. Our focus has been a lot shorter term.

PRESIDING MEMBER GEESMAN: I understand that. I've been in that situation myself before.

MR. BLUE: I understand, but let me get to a couple of questions. Real fast, I want to clarify a previous speaker who asked about the definition of repowering and that there are different definitions.

I certainly agree with that. West Coast Power had been using the term redevelopment, which means our plans would be to build a new facility on the existing site. At the suggestion of Commissioner Geesman, we went back to using the word repowering because that was the terminology that was best understood. I think most people -- well, I will just speak for us, others can speak for themselves, but when we say repowering, we mean West Coast Power, we mean building a new plant on an existing site, similar to Duke at Moss Landing and so forth.

A couple of quick questions, I mean very short answers. We have filed answers to all these questions in our written comments, so I am not going to go into all the answers, but a couple of the highlights I think 2 (a) did the white paper accurately describe the role of aging power plants in the system. I think to the extent that it picked up the issues, yes.

What it did not pick up, did not fully acknowledge, was how the loss of the existing sites for generation could create this kind of complications for the grid and we haven't touched on that at all. Meaning the loss of a site meaning if you have a plant retire and it is not a power plant anymore, it's condos or whatever, that issue hasn't really been looked at.

PRESIDING MEMBER GEESMAN: Do you see that as a land use issue?

MR. BLUE: Yeah.

PRESIDING MEMBER GEESMAN: Your new chapter?

MR. BLUE: Yes, definitely. Again, we heard discussion on the RMR units. Just to give you an example of another issue that could come up with RMR, we had a RMR unit that was designated by the ISO, and it was one of our small CT's down in San Diego, so it is not a big impact to the system, it was like 13 MW. However, it was designated RMR for '04 like it was designated last year. We had to make significant capital upgrade to that plant.

We bought the capital upgrade request back to the ISO, and they rejected it. Therefore, we couldn't do the upgrades, so therefore, we had to retire it. There are those types of situations where the ISO could designate you a RMR and if you have to have capital upgrades because you haven't been putting any -- you've been living on one year contracts, there is a potential that the ISO could reject that, and that leaves you with no alternative at that point. It is just an example of another twist on this RMR thing.

As far as the economics of aging power plants, it seems to me we've not had a chance to actually -- I haven't gotten the numbers back from my folks in Houston about how valid these estimates are, although the staff acknowledge that it is some of the information they just don't have, and they make some estimates. But the description, the actual description of the economics of the plant are correct. I just can't speak to the validity of the actual numbers that you estimated. We are going to get you some comments on that in our supplemental comments.

Let's see, the last question (f), I think are the estimates and assumptions in the aging plants as competitive provide us a capacity are accurate? Yes, we believe that it does. The white paper does a good job of dispelling some of the erroneous assumptions about the aging plant's ability to provide this capacity. Of course, it is all provided. There is a contract to support that.

That's all, thank you.

PRESIDING MEMBER GEESMAN: Thank you. Any other comments.

MR. FLYNN: First of all, I am Barry Flynn with Flynn RCI. I wanted to get back to some of the questions by the commissioners with regard to the economic trade offs on local transmission additions. I think it is a difficult -- the amount of information that is out there in public on that is somewhat limited. The ISO goes through their large process every year, and they feel that under their tariff they can't share all of the information.

The one suggestion that I had is I felt that the consultant's report the commission obtained that sort of looked back at what the economic impact was of transmission that was built some time ago was actually quite useful.

Even though we can't get the up pits, it is harder to predict what happens in the future. I'd like to encourage you, your staff, and maybe the utilities to take a couple of examples of what has happened in terms of a specific RMR reduction due to a specific upgrade, what was that upgrade, and what was the annual savings. I think that kind of activity that you did for major additions on a local basis would be very insightful. Thank you.

PRESIDING MEMBER GEESMAN: Thank you, Barry.

MR. TRASK: Commissioners, we have come across a interesting graphic here and it is supplied by Mary Jo Thomas of the ISO. I apologize I don't have this in electronic form readily handily, we just got the permission to release this publicly. It is just a graphic that compares congestion against the peak of a period of June 2003 through August 2004. What it clearly shows is there is essentially no correlation to the amount of congestion in the system and the peak. You can see on some days when the peak is very low around 1,000 MW, we are getting more than 2,000 even 2,500 MW of congestion.

Conversely, when we hit our record peak or the one big spike in late March, we had a little bit over 45,000 MW of load. We had almost no congestion, less than 500 MW of congestion. We will get this on the website and have people comment on it.

MS. THOMAS: It should be pointed out, though, that also on our July peak -- I don't know if I have the exact number here, I can look, but it was over 1,600 MW, so the point being is that congestion can occur well up to 2,000 MW during a peak. So, this is because -- we have seen this congestion -- on the graph, too, the other thing that should be pointed out is when the congestion started occurring was after the new generation and some retirements started occurring too. So, a combination of those new generation and retirements has caused congestion on the system.

PRESIDING MEMBER GEESMAN: Is that a state-wide number on the graph?

MS. THOMAS: That is state wide, yeah.

PRESIDING MEMBER GEESMAN: Would it be similar?

MS. THOMAS: It is pretty much all Southern California, though.

MR. CARLSON: Is it intra-zonal congestion?

MS. THOMAS: That is intra-zonal does not consider any inter-zonal congestion, so it is congestion from generators located within the ISO control area.

MR. CARLSON: How is that measured based on dispatch instruction or transmission limit?

MS. THOMAS: It is based off of dispatch instruction, so the way I calculated it was if a unit demand was due to intra-zonal congestion, then I counted it as MW towards congestion.

MR. CARLSON: Are you measuring the energy dispatch or the total capability of the unit committed towards the local congestion?

MS. THOMAS: That is the settlement -- the MW settled during the hour of peak, so the settlement demand generation, so I guess it is a integrated MW.

MR. CARLSON: Integrated MW hour?

MS. THOMAS: Yeah, MW hour, so it is the integrated demand during that one hour.

MR. CARLSON: I would submit that is an

understatement of the amount of congestion based on an energy figure as opposed to capacity committed for the purpose I think Mary Jo would probably agree with me as many of these units are committed, brought on at minimum level, as to respond prospectively to the outage of a transmission facility or other transmission lines so that they can be ramped to the top. So, the capacity is in my opinion a better indication of magnitude of congestion than the energy figure. Energy figures would tend to understate.

MS. THOMAS: It might understate it slightly. It would be really hard for us to right now go through and calculate the exact capacity at the moment. This was the best way for me to get a quick look at it, but it does indicate that it has gone out more retirements would cause probably most likely cause more congestion. We've got a lot of new generation coming on line to replace some of the retirements.

It is my opinion that we shouldn't count in advance and say we have "X" amount of MW's coming on line in three months so we can retire a unit in three months. We need to wait and see what happens. What kind of congestion, what other kind of problems is it going to cause on the system. Once we see that it is not going to cause any problems and the load growth is not going to require that unit, then you can consider retiring it. But to say that you can retire it before all of the facts are out is probably not the most smart thing to do because we didn't anticipate all this congestion before hand.

Part of the congestion on there is because the DC line was out too. So, we had to, again, when the DC line was out, we had to call on some units to ramp up because we couldn't get the capacity out in other areas.

MR. TRASK: Mary Jo, can I ask you especially on the event on March 31, the amount of congestion that was seen then, was that mostly due to the fact of which units were on line and the locations of those units?

MS. THOMAS: I don't think we have done a real thorough analysis as to exactly what caused congestion. It's part of the load requirement, where the load is, what generators are running at the time. There are a lot of things involved that would cause congestion. It is very hard to study it too and predict it in the future. We can come up with some predictions, but that is putting in thousands of different assumptions and hopefully assuming that you made the right assumptions to calculate it, or estimate it, or model it.

MR. TRASK: The theory of chaos over rides.

MS. THOMAS: Yeah. I guess the statement that you just made about being able to study and predict the congestion, that is one of the difficulties that I have in how you actually develop deliverability requirements and resource adequacy requirements that adequately pick up these things that are so difficult to understand and so difficult to predict.

I don't personally do the modeling. I have asked some people who do do the modeling, and they said they can get most of it, but it is not guaranteed that they have. I think that any type of deliverability is better than none.

PRESIDING MEMBER GEESMAN: I think there's a conflict of cultures involved though from a operations culture that your organization is forced to prioritize to the bean counter culture which the regulatory system for one reason or another has chosen to prioritize.

I'm not certain there is a good way of meeting both cultures needs as it relates to things like deliverability standards or responsibility for local reliability. I realize there is a limited amount of information that you can actually make public or to provide to the utility under your tariff. The regulatory system wants to know why we can't have 100 percent and why can't we look at that in an open public forum.

I think these are going to be difficult objectives to reconcile. I appreciate the fact that we need to do that in such a way that we don't jeopardize our ability to operate the system. These guys in front of us are on a quarter to quarter decision as to which plants to continue to come up with the O & M costs for.

Greg?

MR. BLUE: I think as far as the issue of predictability of congestion, I think that it is going to get easier once the utilities start actually procuring forward for terms of years, 1, 3, 5. Knowing where the utilities are procuring is a big reason of the congestion, and Edison has stated or it has been stated by others that Edison is buying a lot of power at the border. That in itself physically they can't get it there physically that is going to cause congestion.

Once they start buying forward -- I mean it will become more predictable should I say. Right now there aren't any long term contracts. They are out there buying short, not daily, but short, pretty short. Things are moving around, I agree with that, but that is my opinion, once you -- I think it will become easier once the utilities start lining up their procurement and it is known and people will all know it.

PRESIDING MEMBER GEESMAN: You must have been a big fan of the DWR contracts and the stability they brought to the system. Trent?

MR. CARLSON: I'll just offer one comment. Take Mr. Jones here or Advisor Jones. There is a good amount of deliverability that can be quantified on a sufficiently forward basis. I'll just give you a couple of examples. This will not be an exhaustive list, and Mary Jo can supplement or clarify.

For example, there is a certain amount of in-base and generation in Los Angeles Basin that is required. Various levels, once you hit a certain amount of load, you need a certain amount of capacity based on a forecasted time frame with a forecasted condition of the transmission system best case.

The same exists for San Diego area as well as different slices, if you will, of the San Francisco Bay Area, and then there is the Humboldt area. So, you do have these local, if you will, sub-regional constraints -- I'm trying to pick a word, if it is less ambiguous, but there are these smaller portions of the overall system in aggregate that are quantifiable on a sufficiently forward basis so as to allow counterparties to contract, if and only if the incentives to forward contract exist. I think that is what Mr. Blue is getting at here, absent a reason to do it.

The investor-owned utility companies sought to turn their shareholders and explain why they did something that was counter intuitive to the economic incentives they face. I don't mean to be kicking a dead horse here, but I think this all relates to what are the incentives, and what is the information that is made transparent to the market.

There is a substantial amount of information that is already made transparent to the market. If it were only made available on a more forward basis, and the rules were clear as to who had what obligation for supply and for contracting obligation. So, I don't think we are starting from scratch, and it is not all wide open, undefined, unquantifiable field.

MS. JONES: Don't misunderstand. I'm not arguing against forward commitments, I'm wondering how much of the problem was a load pocket issue you can solve with forward commitments.

MR. CARLSON: I think the majority of it in our opinion, Mary Jo may correct me on that, but that is my experience.

MS. THOMAS: I think that the ISO agrees that if the most serving entities were able to forward contract and have longer term contracts that it could resolve a lot of those issues.

PRESIDING MEMBER GEESMAN: How far forward?

MS. THOMAS: I'm not going to speak for the financial incentive for doing that, but I think forward enough that you can have an incentive to keep the right generation around or build new generation where required and/or transmission that its energy efficiency and demand response, you know, whatever it takes. To have some sort of longer term commitment than what the ISO is able to offer.

PRESIDING MEMBER GEESMAN: That is longer than one year?

MS. THOMAS: Yeah.

PRESIDING MEMBER GEESMAN: Trent.

MR. CARLSON: If I may again. I believe it is the same time frame as incremental transmission improvements. The example that comes quickest to mind is several years back, the Bay Area limit was largely defined by the need for one more 500 KV to 230 KV transformer bank installation.

The deliverability or the need for peninsula generation was predictable several years out looking forward to the installation of that next transformer installation. So, it is things like that, that are quantifiable on a transmission planning horizon. Not all things, but many.

PRESIDING MEMBER GEESMAN: How do I make an apples to apples comparison there? How long a period of time do I amortize the transmission over?

MR. CARLSON: As compared to?

PRESIDING MEMBER GEESMAN: Signing a two-year contract with your company.

MR. CARLSON: If the transmission owner is paying for the transmission upgrade, I would think you would try to make that economic comparison on the most similar basis as possible. You try to -- I don't know if I am understanding you --

PRESIDING MEMBER GEESMAN: I'm trying to determine what is the most similar basis possible, and is that the appropriate way of framing the question?

MR. CARLSON: It seems like if the transmission owner knows that ultimately they face a transmission improvement in the pending time they face a congestion risk, then that defines over a time frame however the utility wants to define it a hedge that could come by way of load management or interruptible dispatchable load versus incremental generation supply or what have you.

PRESIDING MEMBER GEESMAN: That tries to stimulate the utilities decision making structure, but in the past, the state hasn't always been comfortable relying on those instincts. Arguably, regulators attempt to take into account a broader rate payer or societal perspective. As it relates to the transmission investment, let me hypothesize that is a long term asset which the utilities customers will enjoy the benefit for the service life of the asset, irrespective of what the cost recovery factor is or the accounting depreciation is.

A two year contract with your company, though, doesn't confer any benefit necessarily on the rate payer beyond the term of the contract. So, how do I get to an apples to apples comparison if I am the regulator trying to make the decision that is in the best interests of the rate payer?

MR. CARLSON: I don't know if I can answer your hypothetical directly. Isn't the apples to apples comparison start with just simple service continuity, you assume there is no load interruption under the two different alternatives that you are evaluating?

I guess you would have to compare let's just say hypothetically, so we are talking about people or locations, PG & E is looking for incremental supply as compared to incremental transmission import capability into the Bay Area. So, its requests for offers should reflect that it is looking for economic alternatives to incremental transmission costs. So, I don't know -- did I answer your question, or am I completely missing your point?

PRESIDING MEMBER GEESMAN: No, let's address this in any supplemental written comments that you guys choose to file. I am not certain that I have a clear handle on it either. I am concerned, though, that it is difficult if not impossible to make a fair and objective comparison.

I am personally of the belief that the RMR process in my mind may very well be under counting those transmission benefits by attempting to force that amortization or cost recovery factory of the longer term, if you will, societal investment in transmission into a time frame that is more directly comparable to a one year RMR contract. I think that perpetuates some of our reliability problems and a lot of our congestion problems and results in an under investment overall in the transmission system.

MR. CARLSON: We would agree with that

and just to add to that, I think what fits with the approach, if I am understanding you correctly, would also be an exit strategy. In other words, for whatever supply is required to fill the gap like some short term stop gap measure like a RMR contract, there must be a plan to eliminate that contract even before you enter into it. It is not clear to me that is always the case.

PRESIDING MEMBER GEESMAN: Yeah, I agree with that. Greg.

MR. BLUE: I have seen recently a white paper, and I can't recall who wrote it and I haven't read it yet, but I will get my hands on it. It discusses a methodology for how you do the apples to apples comparison. There are people out there thinking about this very topic. I'll see if I can get my hands on it and file it.

PRESIDING MEMBER GEESMAN: Yeah, I think that would be helpful.

MR. BLUE: I have seen it in the last -- in fact, it may be filed under procurement proceeding, I'll have to check, but there is a white paper out there by somebody. I'm not endorsing it, I haven't read it.

PRESIDING MEMBER: Sure. Matt, you want

to walk us through.

MR. TRASK: If there is no more comments on Chapter 2, role of the aging plants, we will note that we are just after noon here, and I would guess that since we have four more chapters to get through that we are looking at a couple of more hours of participation, so perhaps we should break for lunch.

PRESIDING MEMBER GEESMAN: Sounds like a good idea. Why don't we come back at 1:15.

(Whereupon, at 12:13 p.m., the workshop was adjourned, to reconvene at 1:15 p.m., this same day.)

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AFTERNOON SESSION

1:15 p.m.

MR. TRASK: We are on the record. Folks listening on the internet, again, I want to remind you that you can call in if you have any comments. The number once again is 888-390-0784, and the pass code is 21142.

We thought we would move on to the questions in Chapter 3 which are up there on the screen and encourage anybody that has any comments about Chapter 3 to come on down to the pit area here.

I think I will just open it up to general comments about our reliability analysis, both the power flow modeling we did on the transmission system and the result in overloads that we determined would occur, as well as the forced outage rate type information on the generating units themselves.

Any comments?

MR. GULIASI: Les Guliasi from PG & E. I have some comments on a couple of the questions. I think I will comment on 3(c) and 3(d), but not in 3D.

Let's see, with respect to 3(c), the

staff asked that various parties review the sample of power plants listed to insure that there is a comprehensive list of when retirements might occur.

Overall, I think that the list and the listing is reasonable. I want to note that Hunter's Point is not on the list, even though we believe that the plant will be retired in 2006. As everybody here probably knows, the California Public Utilities Commission just last week approved the Jefferson Martin transmission line, which is a major step in achieving the goal of retiring Hunter's Point.

While we are in the process of working out a more detailed construction schedule and reviewing the decision to make sure we take care of all the necessary compliance items, we hope that the line will be constructed by the end of 2005 enabling the shut down of the plant in early 2006.

Can I move on to the next question, 3(d)?

MR. TRASK: Sure.

PRESIDING MEMBER GEESMAN: Let me ask you on that last. You are also moving forward with the different inside San Francisco upgrades that are also considered important to permit retirement of the plant?

MR. GULIASI: Yes, absolutely.

PRESIDING MEMBER GEESMAN: Thank you.

MR. TRASK: In our analysis, we didn't include that plant because we knew it was going to retire.

MR. GULIASI: Oh, okay.

MR. TRASK: The rankings were more for the ones where we didn't really know whether they would retire or not.

MR. GULIASI: Thank you for that clarification.

What we did in reviewing the list is think about the question about whether any of these plants you see here, Table 3-1, are really Southern California plants, Table 3-2 are Northern California plants, if any of those plants would have adverse affects on our transmission system.

It is noted in the staff report that the various transmission improvements that we are making will eliminate many of the overloads, the transmission overloads, that the staff identified.

We do provide a monthly status report to the Public Utilities Commission on various transmission projects. I believe the staff has that information and consulted with that information. If not, we would certainly be happy to provide it.

If the staff would like us to work with them further, to update the power flow models or results of the power flow analysis, we would be happy to do so.

I think that pretty much summarizes what I need to say here. We will supplement with a little bit more information some more comments on that question in our written submittal.

MR. TRASK: Thanks, Les. Any other comments on our reliability analysis? Greg.

MR. BLUE: These are in our written comments on our reliability analysis, but I thought I would just comment on a couple of the items, particularly the --

MR. TRASK: Is your mike on, Greg?

MR. BLUE: Yeah. The classification of the high and medium risk retirements in the Edison and SD G & E area, Table 3-1, just for everybody, I think you know this, but El Segundo does not have an RMR contract and our DWR contract expires at the end of this year. We recommend moving that up to the high risk, similar to the same criteria you are using for everything else in there.

MR. TRASK: Okay.

MR. BLUE: As we said earlier, we think that the analysis of retirements in the San Diego area as it relates to the Edison issue should be looked at. It is mentioned briefly.

MR. TRASK: Yeah. I would like to draw you out a little bit on that. We know that I believe either one of the San Diego plants could fit this, but the scheme of it is identified as needing voltage support there in order for the output of songs to get up there, which is why it is the subject of a RMR. We assume that as long it is a RMR that it would remain available and there would be no effect on the ability to get the power out of songs, and if and when it was no longer a RMR, something would happen that would make sure that you could get the power out of songs.

MR. BLUE: In regards to that, now that you have mentioned that topic, it looks like you guys -- okay, so the last comment I made was in regards to the Edison import limitations.

There are also, and it is my understanding, and I'm not a transmission expert, so I'll tell everybody that. It is my understanding since there are import limitations in the San Diego area --

MR. TRASK: Correct.

MR. BLUE: -- they have a separate, it is not called SCIT, but it is another type of a transmission scheme set up there, and I guess when we were looking on those analysis, I don't know how much analysis was done on that, on the San Diego import limitation. It didn't look like you did anything on that, maybe you did, and I missed it.

MR. TRASK: I believe there was some modeling done on congestion relief effects of the San Diego units. I believe the conclusion was that as long as those units are available under RMR, there would be no effect on the limits of the ability to transfer power into San Diego. If they were no longer RMR, usually it would mean that you have a new transmission line in that area plus a new power plant in that area that would supply that need for those two plants.

I know in the past when we've talked, I

believe you stated that even at that case, Encina might still be needed for reliability --

MR. BLUE: Right, which is what you had just said a while ago. We also noted that in the report you said that in the San Diego area, even without any retirements, I don't know if this included the new proposed transmission upgrade and the proposed Otay Mesa plant, but you had said that there was likely to be overloads even without retirements.

MR. TRASK: Right. We see that in I think all three of the service territories.

MR. BLUE: Okay.

MS. JONES: Let me just clarify. You see overloads, but I think you prefaced earlier this morning by saying that they were relatively small transmission fixes to those?

MR. TRASK: Correct, and that when you have retirements, it just increases the severity and frequency of those overloads by I think some where around 50 to 75 percent.

MR. BLUE: Is that study -- the results of that, is that in here? I didn't see it, I guess that's our point. If you did a study, we would like to see about it. I have not examined the appendixes either. Maybe it is in there and I missed it.

MR. TRASK: I don't believe it is in the appendixes, I think perhaps the only thing that ended up in the report was the statement of the conclusion that retirements in San Diego would not change the transfer capability into San Diego area.

MR. BLUE: All right. I guess we would recommend shining a little more light on that for the benefit of the general public.

MR. TRASK: I did want to emphasize that what staff did was sort of a -- well, it was a preliminary style analysis since we selected these high, medium, low, it was just to examine a range of retirements. What the utilities and the ISO are doing right now goes to a far deeper level with the same 50 units. When that study comes out in November, there will be a lot more definite information out of that.

MR. BLUE: On the issue of forced outage, I guess historical data is one thing, estimates of future forced outages raises a more difficult task. I think in my recollection, and I have to go back and look, but I think under the generator maintenance stages that are coming out from the 39XX and all that, I know the PUC is going to be collecting NERC GADS data, and there might be an opportunity for you as a sister agency to sign whatever documents, confidentiality documents, that are needed for you guys to get your hands on that kind of stuff. Again, that is historical. I don't know if that helps you with future.

MR. TRASK: I wanted to address that a little bit. Vitaly Lee is not back with us, but commented about how that information is available from the ISO. It was our understanding that the ISO data base does not separate actual forced outage or due to mechanical failure or whatever from the economic dispatch when the generator refuses not to generate. Perhaps that is not true, I've heard both ways. We can work more with the ISO on that.

The big missing thing was that we have nothing on the municipal utilities. They don't want --

MR. BLUE: I can't help you on that. I think that is the main thing for now. In our comments we gave you some corrections on what you call Long Beach 8 and 9, it's really more than 8 and 9 involved at Long Beach. We just gave you some corrections here. I don't need to take up the time with the Committee here, but you can note that.

MR. TRASK: Thanks. Very good. Barry.

MR. FLYNN: Yes, I'd like to comment (inaudible). We are sort of disappointed in the lack of unit specific data. I think it is a difficult area. Because it is difficult, it means in my mind, the Commission needs to put more attention to it. I believe you have the well deserved reputation of trying to get useful data out in the public.

I don't quite understand the market sensitive nature of an estimated forced outage rate historically on a unit, on a unit by unit basis. You know, I struggle with this issue when I am asked by my client, the City and County of San Francisco, to look at the outrage rates, the average outage rates, of the units in San Francisco compared to the ISO grid as a whole.

We went to the ISO to try to get that information, they said they could not give it to us. We struggled to try to get it. Basically what they did was they pointed us to a website where it does show on an individual unit basis clear up to practically today whether a unit is out of service.

My understanding is it does not distinguish between maintenance outages and forced outages and has that major deficiency, but economic outages are not included.

It is unit specific, and so the two big draw backs to it is it doesn't distinguish between those two. It is only a four hour snap shot as opposed to knowing when it went out and when it came back in.

When I read what was available to you in terms of this report, it seems like it might have been quite useful. So, I guess I am saying it is not very good, but you know, you had a real hard time it seems to come up with anything on a unit specific basis and anything that was recent. I mean at least it is recent to go back beyond the time period when these plants were owned by somebody else in a different regulatory environment and get data and make conclusions from it to me is not probably the best practice.

I want to sympathize with the struggle

that the staff has been through because I struggle with it myself, but I think that the dedication of the Commission to this area is very important, and I also would caution the Commission to talk about averages. Largely we are talking about plants that are serving a local reliability need and to say that all the aging plants are not worse than all the other kinds of plants, to me sort of misses the boat if there are specific problems in specific local areas.

It seems to me it is a plant specific, unit specific analysis that needs to be done. I encourage you to not give up just because it has been a difficult area.

PRESIDING MEMBER GEESMAN: I think your points are well taken. My own hunch is that this is likely to require national reliability legislation before any material progress is made in getting data. I think I've got a pretty good understanding as to why we've not been able to get what we've requested, but I don't see anyway to really plug that hole until the national legal framework changes, until NERC or whoever the reliability organization is imposes some mandatory requirements. Then I would hope it would be applied to the municipal utilities as well as other owners and operators.

MR. TRASK: We were able to take sort of snap shots of plant unit specific reliability during the very hot months of the last few years. When we look at the time when those plants were called upon, we do have CEMS database pretty good information that shows that they were available when they were called upon. It tells you absolutely nothing about the other ten or eleven months of the year. At least when these units are absolutely needed, what we can gather, they seem to have a comparable forced outage rate with the newer plants during those times.

MR. FLYNN: Is the information that you get CEMS database on a unit by unit specific basis and can that be shared with stakeholders?

MR. TRASK: I believe so, we can check on that. Barry, I would appreciate it if you could e-mail me the address for that, the website you mentioned.

MR. FLYNN: Sure.

MR. MOBASHERI: This is Fred Mobasheri. Earlier regarding Chapter 2 and 3. In Chapter 2 you are defining the benefits from these aging units. One of the most important benefits of these units is contingency. When there is a contingency, these units can produce more power.

In fact, if you look at the figure 2-1, it shows that the during the energy crisis, the energy production from these units went to about 25 percent of the total requirement, where as they are usually producing about 10 to 15 percent.

The reason why during the energy crisis these units were producing, it wasn't because of the energy crisis, it was mostly because of the hydro condition in the Northwest, dry conditions in the Northwest require more production from the generation in California.

These units produce more power when there is dry condition, either in California or the Northwest. They also produce more when there are some large units out like the nuclear plant, like with Song was out for several months, one of the songs unit because of the fire.

They are also producing more power when the transmission is not available because of the fire or whatever is, so I would strongly suggest that kind of benefit should be also mentioned in this second chapter as a benefit of these old units.

Now the question is how do you get these benefits if they are going to retire. Really there is also another category that you maybe should add to this category of active and retire and that is called a stand by.

These units can also be put in the cold stand by, and by cold stand by then you can recall them back when there is a contingency. The owners of these units will not do that for free probably because it doesn't make sense for them to put these in contingency mode and then put them in stand by, but this was the procedure that was used by Edison and PG & E in the old days. They would put these units called stand by and called them back when they were needed.

To create that then maybe they have to be some kind of an option that utilities can pay these option fees and get these capacities in the cold standby rather than retirement, and then with the provision that they can call them back in three months notice or six months notice depending on the option. That way then the generations, rather than disappear completely, then they will be in the cold standby and be called back when there is need for them.

MS. JONES: I think you answered part of my question at the very end. What is the availability from cold stand by? How long does it take to get them back into operation?

MR. MOBASHERI: It depends on what kind of -- three to six months maybe. Some of them three months. When you have hydro condition like what I am talking about you know well in advance, so you can call them back. When you have a transmission that is going to be out and you know it for repair, you can call them back. Even a nuclear power plant if it is going to go out for six to eight months, you can call them three months in advance notice.

Depending on the option fee, you can even shorten that, but that is something that has to be looked into.

MR. TRASK: This is essentially what happened with Etiwanda this year, isn't it?

MR. CARLSON: By the way, I appreciate, I think, everything that Fred Mobasheri just said. I'm trying to think if there was anything I disagreed with. I don't think there is, but just to clarify, we could have probably brought

Etiwanda Unit 3 back quicker, but we did not have the expectation going into the moth ball it would be coming back that soon. We were able to get 4 back because it didn't require some major maintenance to come back. It is not a three to six month range, it was something like six weeks to come back for Etiwanda Unit 4 and it is gong to take about 12 weeks or so to get Unit 3 after some major maintenance. So, what Fred is saying is right on point, and we would fully support that kind of concept and look forward to responding to that type of request for offering from the IOU's.

MR. TRASK: Trent, could you or Roy expand on the differences between cold stand by and mothball?

MR. CRAFT: Yeah, Roy Craft, representing Reliant Energy. Cold standby you have the entire staff of the plant ready to go. In a mothball situation, at least our definition, the plant would be de-staffed, and that is one of the major considerations in returning the unit to service is the qualified staff. Also, in a cold standby -- I mean in these units are normally in cold stand by a considerable portion of the year, through the winter months when we are not called upon to run. Mothball they are actually disabled, fluids drained, desiccation unit put onto the outside or the boiler, things like that, that would require some period of time to remove and restore it to service.

PRESIDING MEMBER GEESMAN: Would you characterize the experience with Etiwanda over the course of the last year as a bonifide mothballing, or was it not quite that far because you had to conduct the auction again one year after the first auction?

MR. CRAFT: In the case of Etiwanda, we were in the process of full mothball. The equipment had been placed, it had not been cut in yet because we got an early enough indication that the ISO was interested in the return of the unit.

PRESIDING MEMBER GEESMAN: What was the situation with respect to the staffing?

MR. CRAFT: The staffing -- I'm trying to give you a percentage, we kept roughly 18 of 36 staff, about 50 percent in another mode, just the core expertise of the station was kept, the rest were laid off.

PRESIDING MEMBER GEESMAN: Had that gone all the way to the second auction --

MR. CRAFT: Without being picked up?

PRESIDING MEMBER GEESMAN: -- without being picked up?

MR. CRAFT: We would have terminated the employment of the rest of the people.

PRESIDING MEMBER GEESMAN: Thank you.

MR. CRAFT: You are welcome.

MR. BLUE: This is Greg Blue again. I also want to endorse the comments that have been made regarding the option payment, the optionality of these sites, also the optionality value also allows some period until we get through the market redesigns that we are talking about, through all the regulatory proceedings that we are getting to.

The other issue is that you can't mothball a plant forever that we are talking about. At some point, the equipment if you drain the fluids, the equipment starts to cease functioning. It starts rusting, especially the ones on the coast. So, the idea of a cold stand by with an option payment to keep staff around is something that we would certainly -- that would be another option for us. We would support that.

MR. LAWHN: I would like to support what he just said. Even if a deep mothball situation, the cost of maintaining the plant in that condition are not zero. They are pretty extensive.

MR. TRASK: I believe we have at least one caller. Is there anybody on the telephone who would like to make a comment?

(No response.)

MR. TRASK: I guess not. Any other comments on Chapter 3, the reliability analysis.

MR. CARLSON: Just one quick one. To key up the SCIT analysis, we are not prepared to give any specific comments today, and we would prefer not to do any studies to prove up any point in our written comments on September 7, but we would like to encourage the CEC staff to follow up with CAL ISO staff because just our feel is that the numbers are understated, and some of the assumptions are not complete to reflect the impact of potential retirements.

For example, there is no mention of inertia or those types of analyses. I believe the ISO is in a position to give some estimates without doing a lot of detailed study to confirm whether these numbers are about on point, overstated, or what we believe to be understated.

If there is to be a supplement issue to this report, we would hope that would be reflected in that report or supplement.

MS. THOMAS: The ISO has provided some comments, we are not going to endorse the scit analysis, there is not enough information there for us. I don't think we exactly agree with the results. Perhaps we could invite you to come in and have a meeting. I don't know to what extent we can help, though, because I think this analysis to do it right, is extremely time consuming.

I would be more than happy to set up a meeting to work with some of our staff on that.

MR. TRASK: The current grid assessment, is that looking at scit as well the effects of retirement on scit as well as the reliability?

MS. THOMAS: I don't know. Is there any of the IOU's here that know that answer or anyone else who is participating in the transmission process? I'll find out then.

MR. BLUE: I do have a question. I read where the ISO was working with the investor-owned utilities on this reliability analysis about retirements at the plants. I note that we haven't been called by the ISO to participate in this. I don't know how we get our input into what they are doing. Nobody has talked to us, we haven't been invited, I know maybe public meetings. I knew it was going on, but we haven't been reached out -- I don't know if you are seeking information from the generators themselves or not.

MS. THOMAS: I believe the generators are open and invited to the transmission process, but if you would like to give me your business card, I'll give it to that group and make sure you get invited to those meetings.

MR. BLUE: I am pretty sure that none of our people have received any calls about that, and so just as we are inputting on this process, we would like to input on this process as well. Are there generators actually showing up and your meetings, besides utilities?

MR. TRASK: I think it may be a little early, Greg. I think right now the utilities are conducting their sensitivity studies that will be input to the ISO and then the ISO --

MS. THOMAS: It --

MR. BLUE: They asked the utilities? Aren't they asking any of the generators about what their opinions are? I haven't gotten any calls from the utilities either.

MR. GULIASI: I don't know, Greg.

MS. THOMAS: There is a whole process where it is opened -- well, it is not open to the public, but open to utilities --

MR. TRASK: (Indiscernible.)

MS. THOMAS: Yes, there is a whole stakeholder group and they have several meetings and take input from anybody. I think there is, I don't know where on their website, probably under transmission section, there's a link to get to the right person.

MR. TRASK: I put that link in my presentation.

MS. THOMAS: Okay.

MR. FLYNN: Let me try to contribute a little bit since I follow all these proceedings. Each utility does their five plus five or ten year plan, a grid assessment every year. As part of the study plan, at least in PG & E's case, they have decided to look at potential retirements. Those meetings are held about four times a year, they are open to anyone who wants to go, but there is no debate there as to whether or not much of a debate as to whether their assumptions were right.

I mean it is really -- what's talked about is if these plants are not there, these overloads exist. It is not debate on whether that is a good assumption or not. In fact, the utilities in -- you know, they say we don't know, but here is a "what if", what if Pittsburg 7 and Pittsburg are not available and Portrero 3, and what if all of the plants are down. What overloads do we see, that is the type of analysis that's going on in PG & E's case.

The ISO on an annual basis does their grid wide assessment. In some ways it tends to check what the utilities have done, but it has a higher voltage emphasis. They are looking at the same kind of things.

You know, I don't think if a generator came in and said we don't think you should assume my plant is going to retire, the utility would say, well, you are probably right, we just ran the studies. So, it is not a debate like that. It is a technical analysis that says if these plants retire, these facilities would be overloaded. So far, at least in PG & E's case, they haven't to the public proposed what they would do if the plants did retire. They would just say these are the overloads. I mean they probably will say in order to relieve these orders, we would have to do this. So far, that is not publicly available, at least at this point in time.

MR. BLUE: The current process that is undergoing at the ISO, what is the kind of time frame of when your analysis is supposed to be complete? Is this like an annual?

MS. THOMAS: Yeah, the results will be out I believe it is the end of October or beginning of November, so they will be out soon at the end of this year, though.

MR. BLUE: Is this year any different than any other year?

MS. THOMAS: Yes.

MR. BLUE: Because of the emphasis on retirements?

MS. THOMAS: Right.

MR. BLUE: Okay.

MS. THOMAS: They previously didn't consider retirements or projected retirements. This year they are considering those.

PRESIDING MEMBER GEESMAN: I want to come back to the SCIT analysis. Trent, did I understand you to say that it is your belief that

the staff analysis understates scit related intra-
zonal congestion?

MR. CARLSON: SCIT related -- let me say it this way. We believe this would lead someone to believe that it is not much of a problem if the capacity associated with the plants identified as high and medium risk for retirement were unavailable. Just based on my slightly aged experience or vintaged experience, it just doesn't feel right to me that with that amount of MW's available, if the equivalent amount of spinning inertia and how that relates to the scit nomogram. It just appears to be understated. It makes it sound like there is really nothing to worry about in terms of Southern California imports.

There is other assumptions about how you make up the difference if these plants were to be retired where the power would come from. I think a little more explanation on that would be helpful.

PRESIDING MEMBER GEESMAN: This is the reference to 1,100 MW of additional import from Los Angeles?

MR. CARLSON: Yes, and again, my information may be dated, but when I was in

California, if somebody said on peak it really won't matter if you are missing a couple thousand MW's of these aged power plants because we will just call LADWP and have them send us another 1,100. It is counter to my experience.

MR. TRASK: I don't believe that is what staff concluded that there wouldn't be a problem. Our analysis of SCIT was rather limited. We can only go in the time we had available, we could only go to N-1. Certainly N-2 would almost make a huge difference. We did conclude that retirements could definitely limit the import transfer capability into scit. I believe just totally off memory here, it is about 400 MW's with the high risk units out.

Then we also did find quite a bit of overloading. The only thing is at N-1, we saw that the fixes were relatively cheap and easy. Obviously, they would still have to be done, and that could take "X" amount of time, availability of components and so forth.

MR. CARLSON: By the way, I don't mean to be overly critical of what you've done. I appreciate you taking a look at the SCIT issue, and I generally agree with your finding, that the amount of Southern California imports are reduced.

I'm just saying that it looks like you have understated the extent to which I would have expected them to be reduced.

Second, it is not clear to me how you are making up the difference to restore the power balance in the southern zone. From my experience, the CAL ISO was not splitting ancillary service requirement, SP 15 versus NP 15, so now I would expect that going forward situation to be even more severe than what my own experience was a few years back.

It would be enough for us to have the report reflect that the studies were not anything like Mary Jo's suggestion that a year's worth of study. It is just the back of the envelope, what's the change in inertia, what's the change in power demand balance, to what extent does zone procurement effect that demand balance in the southern zone. Is it a little bit of a problem, or is this really something that we really should pay close attention to?

MR. TRASK: Right. We are doing some additional analysis in that area. I briefly mentioned that during the presentation. We are trying to do a break down of supply and demand available in the different regions. We did also in a separate part of the analysis, not in Chapter 3 conclude that retirements in the Los Angeles Basin in addition to limiting transfer capability would create that reserve margin problems and that you could very easily have problems meeting load in those conditions with few retirements.

PRESIDING MEMBER GEESMAN: Mary Jo, you thought the numbers did not look right. Can I get you to be more specific, or would you prefer to stay at that qualitative assessment?

MS. THOMAS: I provided some comments from the engineer who took a quick look at it. It was more some questions, did you include this or that. Again, I think they need to have some more information for them to really evaluate it. Probably the best thing to do is get the CEC together with the engineers who work on that and go step by step and maybe they can give them some suggestions on how to narrow this down.

MR. TRASK: I would totally agree. I think the best value we have gotten out of this study so far is meeting one on one with the people who really deal with this stuff every day.

COMMISSIONER BOYD: We accept that offer?

PRESIDING MEMBER GEESMAN: Matt, do you want to keep pushing us through this?

MR. TRASK: Sure. Any more comments in Chapter 3? Let's move on to the future of aging plant operations.

Here we tried to characterize what are the likely future products that are going to be needed by the IOU's. We concluded that 5,000 MW's of peaking and load following capacity were needed as soon as next year, another 5,000 by the end of the decade. The question was whether or not the aging units would be able to participate in that request for offers.

Any comments on Chapter 4?

MR. BLUE: I have a specific question on that specific topic. What was -- I'm reading out of the report that says, "As load growth continues and DWR contracts continue to expire, this need will increase." Then you've got the number. What was the load growth based on, the growth load we have seen this year, what load growth are you estimating in your forecast of this topic?

MR. TRASK: That is a good question. I

don't believe we were basing it on the load growth that we have actually seen this year because this analysis was done before the summer growth hit. Al or Angela, do you have any?

(Inaudible.)

MR. TRASK: You folks probably couldn't hear that. She said that load growth was three to four percent a year, which is a rather standard prediction for load growth.

MR. BLUE: Based on what we have seen this year, you wouldn't adjust that at all, just purely a forecasting --

MR. TRASK: Well, this is constantly trying to hitting a moving target. Staff did their 2004 summer assessment after this analysis, and we saw some surprising growth. If we were revisit and do this over again, I imagine we would revise those numbers.

PRESIDING MEMBER GEESMAN: This is a particular concern of mine, Greg. We update our demand forecasts biennially. You know, it takes long enough to turn the ocean liner in terms of the data that needs to be brought on board to define that cycle as a two-year cycle. Our demand office makes some rough adjustments to it, and we have published either two or three such adjustments this year that attempt to reflect experience through I think April. I would not attach much precision to that, that is a tool that was really designed for a ten-year horizon, and as you try to bring the refraction up to an earlier period of time, it is not capable of a very precise application. I think we need to have a certain humility about any of our short term load projections and assess whether it is best to err on the high side or better to err on the low side.

In the area this year, the extent to which you can attribute the higher growth to economic conditions, and it is not clear to what extent we can attribute that to economic conditions, but to the extent you can, our demand office typically is of the belief that that is a borrowing or acceleration of future growth, and as a consequence an adjustment will be made in an out year to bring the projected growth down a bit to account for economic growth occurring more rapidly than had been anticipated.

I think people attach more precision to some of these load projections. In fact, the methodology will bear out, it is a consequence it is probably a lot better for policy makers to focus on both the uncertainty of the projections we made and a risk assessment as to whether you would rather err on the high side or on the low side.

MR. BLUE: I agree, and I'm not trying to assign anything to these numbers. This is just a magnitude issue, and you are showing the magnitude is pretty great. Another one or two percent, and you have a great thing to do, so I just had some questions. I'm trying to seek some clarification from that piece.

MR. TRASK: Looking further down the questions. We talked about some of the processes that are in place, the proceedings under way that would affect the future of aging plant operations. We have questions down here as to whether we accurately characterize the PUC's resource adequacy proceeding and also whether there are other options for insuring local and zone reliability. Comments?

MR. BLUE: I will continue on. I think the discussion of resource adequacy proceeding at the PUC is accurate. Again, I'll sound like a broken record, but we would like to see the Energy

Commission involved in that proceeding in a way of supporting the resource adequacy requirements, acceleration, supporting deliverability standards. I don't know if you, the CEC normally participates in other agency proceedings, but now days with the Energy Action Plan and the three agencies working together, it was my understanding that there was going to be more of that happening so that everybody is going to be on the same page. If so, I would again that would be my recommendation to include in this report which hopefully will move forward with some action.

PRESIDING MEMBER GEESMAN: Let me give you kind of a good news/bad news response to that. The good news is we are participating pretty intensely in that process under a so called collaborative staff arrangement. Under that process, we do not appear as a formal party. Our staff subject to the direction of Commissioner Boyd and I, actually under the IEP process, is participating with the PUC staff in developing white papers and assisting with the drafting of some of the decisions.

The bad news is it is a pretty invisible process, there is not a very high profile attached to it. We don't write a lot of letters to the governor or anything. I will say Commissioner Peevey and I jointly issued a statement at the pre-hearing conference in response to the governor's April 28 letter and strongly trying to direct the process to subject to a majority voted his commission to accelerate the resource adequacy requirement to 2006.

COMMISSIONER BOYD: You don't know how I've been biting my tongue and not making nasty quips about I hadn't heard of Commissioner Peevey's letter until you reference it. I was glad he read our IEPR and took it to heart, apparently, but humans are humans, and turf is turf, and we still struggle. We just hope the door doesn't close in our face sometime.

MR. GULIASI: Following on the theme about turf is turf. I guess I was struck by the last paragraph of the chapter pertaining to municipal utilities. I really don't mean my comments here to be gratuitous, but the paragraph does note that the staff was not able to obtain information from the municipal utilities, and to the extent that this whole issue of resource adequacy is really a state-wide issue.

I would encourage you to be persistent to work with the municipal utilities to try to bring them into play here and understand their situation just as the light is being shined on my company and my sister investor-owned utilities, let's find a little light on municipal utilities.

I'm not saying at this moment that they should have identical or similar adequacy requirements imposed on them, but I am saying that to the extent that this is a state-wide issue, a state-wide problem that would require state-wide solutions, it would be incumbent upon everybody to work together on this problem.

I encourage you to be persistent and try to get the information you need so you can address this problem at a state-wide level.

MR. BLUE: On the question 4(c), asking what are the other options available to insure local and zonal reliability, I guess I would, of course, in the short run short term contracts and long run, of course, repowering. I think based on what I heard today, the option of the cold stand by is another option that should perhaps be included in this little piece right here. I didn't put it in my comments, but this would be a good place for that type of option to fit in.

MR. TRASK: Greg, would that cold stand by concept fit in what a capacity market as well?

MR. BLUE: Fit in with the capacity market?

MR. TRASK: In other words, could you buy and sell capacity in cold stand by?

MR. BLUE: No, but the way my -- the way I would do it, I would think that if somebody is buying an option, that is basically what a utility would be buying an option on a plant. You are committed to whoever is buying the option. I don't know if you could go out in the market then and market. I haven't thought a lot about it from that point of view. I have to think about that a little bit.

To me, the option payment is enough to keep you available to sell to whoever is buying your option. That would be like another form of a contract. I'll think about it some more.

MR. FLYNN: I had one suggestion in this area. I think it was the year before last I helped the City and County of San Francisco provide a ten MW demand, be it in their LARS process, and I think they are contemplating doing something similar next year.

That process is a very opaque process. I believe that load curtailment per say has a lot different characteristics than generator. My experience is the load, you know, it is not as difficult to have it available, but it is more difficult to call on it. So, it has a different economic characteristic in that it could be very competitive in terms of asking for a smaller payment than the RMR generator asks for. When you look at the economic consequence and when you call on it, you know, you might be asking more than what it costs an RMR generator to run.

I'm not sure -- but that is the utility systems. You don't want to sell nothing but baseload. You don't want to install nothing but peaking. So, it seems to me like there is no peaking resources for RMR services from the standpoint of it could be the last thing to be called on, the ISO didn't pay much for it. When it calls it, it is going to pay a lot more than when it called on the RMR generators, and I have no confidence in whether or not that was taken into account when the economics of that demand bid in to the LARS process was looked at.

I think maybe the Energy Commission could help from a generic standpoint. Think about how load curtailment can participate in providing local reliability services in an economical fashion.

PRESIDING MEMBER GEESMAN: Barry, if I'm not mistaken, San Diego Gas and Electric's long term procurement or perhaps it was their interim procurement had a 30 MW demand bid approved by the PUC. In my knowledge, that is the largest that any of the California utilities have actually embraced, and I can't say I know how it works. I believe it was part of San Diego interim procurement that was approved at the same time Otay Mesa and Palomar were approved by the PUC. Do you happen to know if that was based on a local reliability need or --

MR. FLYNN: I don't think that it was, but I'm not certain.

PRESIDING MEMBER GEESMAN: I'll take a look at it, thank you.

MR. TRASK: Our final question is this chapter was whether or not we had accurately characterized the natural gas use of the aging plant sector and the effect of that use on the natural gas market. It was a pretty short section of this study.

We frankly expected it to be a larger section, but our analysis showed that essentially there would be very little effect on the natural gas market from either retirements or continued reliance on the aging units. Any comment on that?

MS. JONES: I guess I would like to note a concern. It appears that the staff kept the production from the aging facilities at 20 percent capacity factor, and I guess the time when you would be most concerned about natural gas consumption would be in a low hydro condition where you are relying heavily on natural gas, and you have natural gas infrastructure constraints.

So, I think you may have understated some what natural gas impacts could be.

MR. TRASK: Right. It is worth further consideration.

MR. WEISENMULLER: Matt, I just had a couple of follow up questions for Greg. (Inaudible.)

COMMISSIONER BOYD: Can we get closer to that mike please.

MR. WEISENMULLER: Sure. I have two

questions for you. One of them is easy, and one of them is harder. So, I'll start with the easy one. You have talked in your comments about capacity markets and you filed 55 pages here. If I recall correctly, your company filed an ex parte with the PUC on its vision for capacity markets. I was just curious as to why you didn't file it in this docket?

MR. BLUE: Consider it done.

MR. WEISENMULLER: That I think would help the record here. The other question was, earlier on, one of the things that comes out from the report is that these existing units are very good to provide ancillary services and for cycling. In fact, much better than new combined cycles. At the same time, as you mentioned a lot of interest in repowering these units. I think all of the proposals I've seen to date basically flip them to combine cycles. So, the question in part is how do we maintain that sort of operational advantage and get a more efficient and cleaner configuration there.

MR. BLUE: I don't have the complete answer for you, number one, but I will give it my best shot.

Some of these facilities and we feel that for example, our Encina unit down in Carlsbad, they are properly maintained. Our operators tell us they can run for another ten to fifteen years without any problem. As somebody identified earlier, you said that some of these plants can be run indefinitely. I believe it depends on the situation. Some of our plants are just too old. Long Beach, for example. Our oldest turbin there is a 1924 installation. They move up, and then the next one is in the 40's and in the 50's, so some of the equipment just has to be replaced. If the value of that existing site is critical to all the things we have been talking about, then a repowering needs to happen.

I hope some of the other generators will speak to this, but at some point, the equipment physically becomes unsafe for the worker. You can't run it, you can't get the benefits from it, therefore, if you want to enjoy the benefits of the current infrastructure at that site, then repowering would be warranted at that place, at that site.

I don't know if that.

MR. TRASK: Greg, let me ask you about

that. It sounds like you are saying that there are some components that whether economically or engineering wise, you couldn't replace and that you would rather go to a repowering. Would that be like the entire turbin? In other words, we have seen some of the units replace their turbin blades, put in different re-heaters and so forth and boilers.

MR. BLUE: Again, it all depends on if there is a contract. If somebody wants to pay you to keep those features available -- although if you structure a contract such that you want to keep that feature available, yeah. I mean we will do those types of things. We haven't seen those yet. We don't see them. Right now we don't see them this year, we might see them next year. We don't know.

MR. SMITH: Greg, the confusion I have is when we talk about repowering today, we have been talking about replacing it with combined cycle. I think what Bob was getting to is can a repowering result in a steam boiler that is more efficient and cleaner. It has all the attributes, the load following attributes and so on that are more efficiently done than can be had with a combined cycle. So, is that --

MR. BLUE: The short answer is yes. It can be done. Once again, you've got to get the right incentives out there.

MR. CRAFT: If I might comment. To answer the one gentleman's question about can a combined cycle meet the needs? It depends. There are trade offs. If you are going for the brand new ultra efficient advance gas cycle gas turbins, no. My company has constructed several of those across the United States in the last few years, and the turn down ratio on those units is very poor. Emissions goes through the roof, efficiency goes through the roof.

On the other hand, yes, a conventional steam turbin boiler combination could be built and has been built that will meet all the emission requirements and high efficiencies. You can build a combined cycle plant that doesn't use the super high temperature firing that they do today and to get the very low heat rates. But you are going to end up with a combined cycle plant that is if you want the flexibility, you trade off efficiency. You are going to end up with something around the 10,000 BTU per KW heat rates that are representative of the aging plants. You can get the efficiency, or you can get the flexibility, but right now technologically, the two are kind of hugely exclusive.

MR. SMITH: Did I understand you correctly, is it the high firing temperatures that are in the ultra-efficient gas turbins that are a limiting factor in terms of the flexibility of those machines?

MR. CRAFT: In some cases, yes. In order for the machine -- in a gas turbin unit, about two-thirds of the energy goes into the compression cycle to compress the air to feed into the combustion process. To get that kind of efficiency, the tolerances in the compressor section are extremely tight, and they are all designed around operating at the sweet spot of the energy curve which it is designed for 100 percent of its name plate. Anything off of that, the efficiency goes way down. Your energy going into compression goes up above the two-thirds point, and the efficiency just goes down. The emissions just also sky rocket, NOX, CO, CO 2, everything goes through the roof.

The machine manufacturers will tell you

that they can have a machine that is a great turn down ration, which it is, but when you integrate that machine into a system, an entire generating unit, then you have to have a SCR on the back end of that thing that it is so large as to be non-economic. Anything below like 60 percent turn down ratio, it is just not economic. Whereas a steam plant, much more amiable to those kinds of changes to turn downs and design.

MR. BLUE: Just a quick follow up, I think where that leads you is if you do see a fleet of base load plants coming in, then in order to regain some of the same characteristics, you are going to have to get a fleet of peaking plants. We don't see a lot of those coming in yet, except on the emergency basis of the crisis.

If you have the peaking plants available, and the base loads, then the operator can do what he needs to do with the plants to follow the load.

MR. TRASK: Any other comments on that Chapter 4? Moving on, then to Chapter 5. Here we talked about alternatives to the aging boiling units, and we actually had quite a bit of discussion on this already. We identify a range of things that could replace a retired unit and specified that the mix of those technologies employed would likely be very different, depending on the unit. We did not unit specific analysis in that area. It is certainly something that could be done.

Any comments on the alternatives to aging units?

MR. BLUE: I didn't quite understand question 5(c). We didn't have a comment, but I also really understand what the point of this question was.

MR. TRASK: Right. One of the things that we said would likely replace any retired unit would be increased generation from existing power plants. We did not differentiate those between IOU and municipal power plants or just general ability to transfer power from one system to another.

PRESIDING MEMBER GEESMAN: That sounds like the 1,100 MW from Los Angeles.

MR. TRASK: Correct.

MR. BLUE: Okay. We have no comment on that question.

MR. TRASK: We did actually discuss this

quite a bit earlier in the more general sections.

With that, I would like to move on to Chapter 6, the environmental chapter. Tim, Rick, and Matt maybe you could join us too. We'll start off with air quality. The air quality section. We did have a couple of general questions there, and then we have specific questions for the aging plant operators and one from Mirant. I'll just throw it open to general comments right now on this chapter.

MR. HEMIG: Okay, I'd like to say a couple of things. Tim Hemig with West Coast Power.

A lot of things I would say in response to these questions is very similar to what we raised earlier in our presentation. We also have very specific detailed suggestions and language changes that we provide in our written comments which I won't read verbatim, but anyway I will get the general points out here.

In the air quality section, we think it is good accurate information in there with a couple of short falls in general that I brought up earlier. Really it is focused on the evaluation of replacing the retired units and how that might occur and adding some additional language in the white paper that discusses more similarly sized combined cycle and how that might replace retired aging power plants, and then doing a short term emission comparison to demonstrate the net air quality improvements that might create at the facility.

We've made some comments along those lines, and you will see them in our statements. I think making a short emission comparison is most appropriate, and like I raised earlier, because that is what affects air quality. Air quality standards are concentration standards that are one hour or eight hour standards.

I think when you are looking at it, that's the best comparison. Another point I think that the white paper needs to have some expansion on is a discussion about emission reduction credits. Basically, the emission reduction credit program creates some net air quality benefits by itself, and especially when you do a repowering project, there are a couple of opportunities where the ERC Program, in a repowering scenario, will create some benefits. I think those should be flushed out in the white paper, specifically even when you shut a unit down and you hope to bank some emission credits, there is some discounting that occurs there. Those are basically discounts that goes to net air quality benefit. We provided some specific details in here where those discounts can be as high as 50 percent in some districts.

MR. TRASK: Tim, can I interrupt you there?

MR. HEMIG: Sure.

MR. TRASK: From my understanding is that the amount of discount is basically based on the location of the new facility compared to the old facility.

MR. HEMIG: No, I am actually talking about pure shut down emission reduction credits. When you shut down a power plant and actually don't have a project to replace it and you just want to bank the credits and you didn't have a lot of operating hours, operating hours themselves can result to 50 to 100 percent reduction depending on how many hours you had.

Some other districts they do it differently, but those reductions can be substantial just by the number of hours that you operated. Then they also discount you assuming you have employed best available control technology. Those discounts can be as high as 90 percent.

I think my point is that there should be some discussion in the white paper about when you do a repowering project, that you are going to net air quality benefits associated with those kinds of discount programs, in the ERC side of things as well as when you go to apply those off sets towards your new units, there is additional discounts, like a 20 percent surplus retirement, which all goes to the net air quality benefit in the program. It reduces on a permanent basis all those emissions from the inventory.

You offset those emissions based on the maximum worse case permitted emission levels, regardless of if you ever run it at that level. That is how you offset it, so there's a substantial discount. I think those should be added into the white paper.

Further provided specific criteria in our written comments about how you might go about expanding on the comparison of air quality benefits associated with the repowering project. Those criteria would be using similarly-sized combustion units in your comparison, not substantially larger facility replacing a small facility. Also focusing those comparisons on the short term emission standards and rates like pounds per million BTU, pounds per MW hour. I kind of explored those things earlier, so I won't really say anything more about that.

This is basically answering the questions (a) and probably (b) as well in your list there.

MR. TRASK: Right. Thank you. Other comments. On (c) we've asked specifically for those plants without SCR and very specifically for Mirant Portrero 3 and Pittsburg 7, Contra Costa 6.

MR. OSTERHOLT: I'm Mark Osterholt with Mirant. We will be providing written comments, but I would like to address 6(d). Regarding Portrero 3, we have planned to install SCR or Portrero 3. That project right now, the building permit has been appealed on that project, so we are uncertain as to actually when that will be installed.

We are working very closely with the ISO to work on managing Portrero 3's operating in 2005, as well as getting the building permits.

The other units that were mentioned here are Contra Costa 6 and Pittsburg 7. Those two units, neither of those units have SCR's. At this point, we do not plan to install SCR's. If we did have a contract, longer term contract, that would essentially assure recovery of the capital invested, then we would move forward with that. At this time, there are no plans to install SCR's in those two units.

MR. LAWHN: Yes, I'm Bob Lawhn with Reliant. I am the Environmental Manager of the West Region. We concur with the comments made so far. Our written comments, I think, are going to elaborate a little bit on the number, the 10 to 15 percent number that's in the report. We are not questioning that number, but I think it refers to the plant's running in typical load following mode.

I think we are going to emphasize that all the individual plants, the different technologies, are following load differently. They are designed to follow load differently. As a result, the emissions are different, and we believe in some cases, you know, a new combined cycle could actually produce more area emissions and have more of an air quality impact than the existing boilers. That is one of the things I think we will add to some of the comments made so far.

MR. TRASK: That is one thing that we found in our CEMS data investigation that indeed some new combined cycle plants are suitably higher in emission rates than some of the aging units.

MR. GULIASI: Les Guliasi with PG & E. I want to first talk a little bit about some issues regarding a particulate matter, regulation, and then talk a little bit about the environmental requirements at both Humboldt Bay and Hunter's Point.

Again, I'll have some written remarks to draw your attention to some of the discussion about particulate matter. I'm going to try to provide those comments as a way of being helpful, not necessarily to draw attention to a deficiency in the report.

In our earlier data response, I think it was back in June, we also talked a little bit about particulate matter regulations and we noted that there are current or pending best available retro-fit control technology rules that affect

Humboldt Bay, but there are as we noted new regulations being developed based on Senate Bill 656 that was passed last year.

That bill would require that particulate matter, include NOX and SO 2 be minimized from areas that are not currently in attainment with their quality standards. The North Coast Basin where Humboldt Bay Power Plant is located is not in attainment of those particulate matter standards. While the Air Resources Board is in the process of finalizing regulations, we don't have any particular schedule or costs associated with what the compliance requirements may be.

Again, I didn't want to raise an issue that necessarily required further elaboration or analysis. I thought you might just want to be aware of that point.

With respect to Humboldt Bay, again, Humboldt Bay units 1 and 2 will not be retro- fitted with SCR because that plant is in attainment, is in a district that is attainment for NOX. I think that the paper accurately identifies that point. We are not sure what the impact of future emission requirements might be on Humboldt Bay with respect to a more stringent cooling restriction. But we are currently evaluation those impacts, and we can talk to you about our analysis as you kind of keep your eye on what regulations do come out both in terms of air as well as water regulation as they affect Humboldt Bay. As of now, we have no plans to retire Humboldt Bay.

Hunters Point, everybody is aware that we have an agreement with the City and County of San Francisco that we will shut down the plant once the transmission line Jefferson Martin is completing and all the associated transmission upgrades.

That plant is facing or would face more stringent emissions requirements. We are working diligently to insure that we don't have to make costly investments in that plant, given our scheduled retirement of that unit of that plant.

We will provide a little bit more information about that in the written comments.

MR. TRASK: Thank you, Les. Any other comments on the air quality section of Chapter 6?

(No response.)

MR. TRASK: Then I would like to move on to the Biology Section, which was focused primarily on the once through cooling systems used at I believe 15 out of the 22 plants that we looked at.

I wanted to briefly talk about Tim's comments during the first part of our study. The statement we said where impacts might be more than one spot. Part of that comes out of I guess you could say our experience in environmental law in general, where you have significant controversy that generally would kick up your analysis to a more stringent level.

It is absolutely true what Tim said about the Regional Water Quality Control Boards. The ones that we consulted with didn't generally see a problem in this area. However, we did also consult with many other resource agencies, Coastal Commission, the Bay Conservation, Building Commission, the Department of Fish and Game, U.S. Fish and Wildlife Service, and the National Marine and Fishery Service, and they were uniformed in saying that they felt that the studies that had been done to date were not rigorous enough, were not capturing the potential for impact. They felt that perhaps there were a lot more impacts than people thought. They even proposed that this may be an area that you should look at rather than shutting down commercial fisheries as a way to help the overall eco system.

Personally, looking at all the information available, looking at the stance of these parties, that is where I said there was an information gap. I do not see enough information to back the conclusions of either side of that debate. That is where we concluded that there was this gap. With that, I will throw it open to comments.

MR. HEMIG: Tim Hemig here with West Coast Power. I think I recognize what you are saying, and I think it might be better, then, to put maybe some less conclusionary statements in there, then, and put a little more information on what the water boards have determined and what they have recognized and findings and permits.

Probably the best example and comparison that I have found to date is the South Bay permit that is currently a tentative order. I think it is up for adoption next month, so it is a very current proceeding and a very very good example of data adequacy from a 20 year old study and of a current study.

A good comparison of the findings, the results are that the findings are nearly identical, regardless of methodology or time frame when the study was conducted, and that the impacts again were documented as very insignificant on the order of I think the range was -- this is the impact to adult fish populations in San Diego Bay. The low end of the range was .003 percent, and the high end of the range was .03 percent impact to adult fish based on maximum flow of the facility at full potential to circulate cooling water.

I think it is important to recognize that in the white paper, leaving the uncertainties and the discussion about some of the uncertainties is appropriate, but at least shoring up the side that there is some findings and factual information out there that implies that the data may not be as inadequate or as uncertain as the way it is portrayed currently in the report.

I also had a couple of more comments, actually question (e) about once through cooling. I've said this before and I think it was in our original set of written comments that there should be a discussion about the benefits of once through cooling as well as when you do a comparison of once through cooling compared to wet, dry, or hybrid cooling systems, I found that there is a number of benefits that you might get out of once through system, including the low cost and most efficient cooling method that you can use is the sea water cooling, or once through cooling.

Energy penalties associated with the wet and dry cooling, those require more fuel to produce the same number of MW's and also would also result in more air emissions associated with different alternative cooling system compared to once through.

I've got a number of them. I won't go through them in detail, but I think those should be evaluated in our written comments, and there should be a balance approach to the report that also has some of the benefits included in it.

I think I had a couple of more things. I had some specific requests in the report for deletions and changes to the report. It goes back to the part of the Regional Water Board's jurisdiction and recognizing what they have said is factual and where there is a discrepancies as to what the water boards have determined. I believe it is appropriate to take some of those statements out of the white paper if they are contrary to what water boards have found.

Those would be where there's a finding and NPDES permit that says that data is adequate or data has determined or has resulted in a determination that there is no significant impact. Those should be included in there.

Then I have one specific area, it is about technology on cooling systems and how well technology works to reduce impingement and entrainment. I think we should include a paragraph about what kind of technologies are already in operation on these aging power plants.

There is a section that there is a very short section about that, but I think it should be expanded to include things about the velocity caps on some of the intake structures and how well those work to reduce impingement. There are results from installation of velocity caps at El Segundo, for example, that resulted in 95 percent reduction in impingement. I think it is important to recognize that they do have technologies that are very effective in reducing impingement currently installed and maybe put some description about how effective those are.

Those continued to be recognized by the US EPA as best technology available, even in the Phase 2 regulation.

MR. TRASK: I believe some of that information, not all of it, is available in the Appendix A of the report.

Rick, did you want to respond? This is Rick York of our biology staff.

MR. YORK: Rick York, Bio Staff. We, too are familiar with the preliminary results of the South Bay Project 316-B study. What we have found that each of these projects when they do their study, do have different impacts. The results of the studies, as Tim knows for Morro Bay and Moss Landing, determine that the impacts were quite significant.

In that case, the data was determined to be old and of little value, and that's why a study was done. The results for those projects, which have been before the Commission are quite different than what they were down in South Bay.

That completes, I think, a little bit more of the discussion that there are different impacts at different facilities, and people need to recognize that.

The other, we are too, like Tim, learning what the new regs are going to require, and the learning curve is pretty steep there. We do recognize that some of the old technologies do still work. Velocity cap is one of them. For some of those projects that do have a good design, obviously we get credit for that when they are up for their renewal of their NPDES permit, so if we do need to elaborate on that in this report, we will.

What were some of the other points that -- one thing about cumulative impacts, Tim mentioned earlier that he felt we shouldn't be discussing that. I respectfully disagree. One thing that hasn't been done but has been continually been mentioned to people is that there hasn't been any cumulative affects for the South Bay Power Plants, and that is the issue that these other agencies we consulted, they all would conclude with that statement, that by the way, we need to look at them individually through the NPDES permit process or power plant licensing.

We also must not forget that cumulatively, they could be having a significant effect on among places like Santa Monica Bay. So, we would like to continue to be able to have that comment in our report.

There are two things that are going on at the Commission that might be of interest to people. For the Huntington Beach Project, their 316-B study is almost complete. We are about to do a what we consider the first cumulative affects analysis, kind of the back of the envelope type analysis. This is the first time one will be done for coastal power plants in Southern California. That will be taking place in early October.

We do know that the public interest energy research program at the Energy Commission is also going to be looking into working with Moss Landing Marine Lab to begin an overall cumulative affects analysis for the coastal power plants in California. So, we do feel this cumulative effects issue is very important, and we will continue to bring this issue forward at every opportunity that we can.

Bob?

MR. LAWHN: I'm Bob Lawhn with Reliant. I think I pretty much agree with a lot of the comments that have been made. I would say the report I think adequately captures the state of the 316 rules, and the complexity and magnitude going forward, I don't think the full impact of the regs will play out during the study period of this report.

However, I think the bottom line is that this point, knowing what we know and reading the rules, it is not a retirement decision at this point. It is not something we can point to and say would lead to a retirement decision.

There may be information gaps, there may be cumulative effects that need to be looked at. I expect you go to Texas and the Gulf Coast or up the East Coast and survey all the different agencies and they would say they have information gaps, and there are effects that need to be analyzed.

It is important and could impact the cost of compliance, but at this point, I think maybe the bottom line is that it is not clear that this is a retirement decision. Maybe that is where it needs to kind of stay at this point, or be noted that it is there, but it is not something that is automatically going to lead to retirement. It definitely is a sort of one more straw in the bag, I guess, for the old game list not getting paid to walk -- thanks.

PRESIDING MEMBER GEESMAN: Let me jump in here. I'd say that this is a staff white paper. I think there is considerable value in getting a good slice of the staff's perspective on this issue.

The next step is going to be the committee coming up with a committee draft, which will be much more focused on policy recommendations than on going back through the empirical information developed in the staff white paper.

On this particular topic, the bottom line I drew from the staff white paper is that this is unlikely to influence retirement decisions during our study period. As a consequence, I am inclined to give it some what minimized treatment in our policy recommendations.

I'm particularly reluctant to get involved in a generic discussion of a subject which is intensely litigated in a couple of our siting cases. I think we are much better served as a commission to try and refrain from that generic policy discussion and allow those cases to be decided on case by case specifics.

Those of you looking for more from the Committee on this topic are likely to be disappointed. I think we are going to largely try to benefit from what has been written, take into account the comments that each of the parties make, but not feel compelled to address policy recommendations in this particular area.

MR. LAWHN: I think that's wise because there's a legal challenge right now pending to put a stay on the 316 rule, so I think it is an appropriate proposition to take.

MR. HEMIG: West Coast Power supports that as well, and I think my point is just the white paper -- we are not writing the white paper, so the best we can do is throw our comments in at this time. I think there is another side and pieces of information that you should recognize. We do support that it is not carried out in the policy part.

PRESIDING MEMBER GEESMAN: Yup. Matt, where are we?

MR. TRASK: I think that might conclude our discussion of biology, unless there are any additional comments. If not, we can move into the last section which is Land Use, Socioeconomics, and Environmental Justice.

We did hear early that we had some gaps in our socioeconomic analysis, especially land use. There may be some issues that we missed, and we would certainly welcome comments. I believe we had a fairly thorough discussion of land use issues at the plants understudy, but certainly we were not able to get a lot of information about property taxes, franchise fees, and so forth. Part of that was working out confidentiality and things like that.

It is something that we could certainly step up a little bit more analysis on that area. I'll just leave it open for comment.

MR. BLUE: Greg Blue of the West Coast Power, the land use issue, of course, desalination plants and the synergies with the coastal power plants. There is really only a brief mention of this in the report, and I think it was worthy of at least two brief mentions.

I don't know if you guys can do any policy on this, but it is certainly needs to be recognized in a higher fashion. I do have a particular question about a paragraph on page 100 and why it was included, the one about The

Surfrider Foundation and the fact they don't like desal plants, and what is the purpose of this statement being in this report.

I'll give you another one if you want an opposing view on this.

MR. TRASK: Sure. We wanted to capture where we could community input, I guess you could say, to the plants.

MR. BLUE: You said that in the previous paragraph before that, that there has been expressed public concerns. What is the purpose of singling out this one participant in a proceeding and community hearings on desal, and that you have their last statement which seems some could say a negative statement? I would say. They say it is added incentive to keep a potentially dated and dirty plant open.

I am trying to understand what's the point of having this in here, I guess.

MS. ALLEN: I can respond to that. This is Eileen Allen of the Land Use and Traffic staff. Your point is well taken. That discussion could be more balanced, and we will expand it. I put that item in there in part because it was in the context of desalination, and Surfrider has been active in that discussion.

Also, he had this statement that these were all "dirty plants" so it was in the desal context, but at the same time he was referring to kind of a broad pollution related statement. There was community sentiment that was related to desal, but also it was related to these older plants.

MR. BLUE: As I say, this is not going to change the report, it is just when I read it, well, where did the other half.

MS. ALLEN: That is a reasonable comment, so I will work put in some other material. I need to warn you, though, you may face seeing some discussion of the growth inducement potential that desal can have for the communities in that area too.

MR. BLUE: We are not a desal developer, so I will just make that point.

MS. ALLEN: Right.

MR. BLUE: You can say whatever you want about it. I am just saying at the end of the day, most of the desal plants in California are going to need to be sited at coastal power plants.

MS. ALLEN: Discussion of the synergy

between the power plant and the desal is reasonable.

MR. TRASK: Let me kind of zero in on that, Greg. I don't know if we want to spend a lot of time in this area, but my feeling is about desalination is that there's been some what of a drawing back of siting these for sea water, using sea water. Now more developers are focusing rakish water, rakish brown water, and there seems to be quite a bit of opportunity for that here in California.

We also had one large facility sort of fall through the sponsor backing out. It was my sense that perhaps there is a little bit less motivation right now for siting sea water type desalination.

MR. BLUE: I would refer you back to the presentation that Lon House made, last week. Were you at that?

MR. TRASK: No, but I heard it.

MR. BLUE: It was pretty dramatic about the water situation in the West. Just like we need every single power plant in California, we are going to need every single desal plant in California that we can do eventually. I did not resubmit his presentation in this docket, but I would be glad to do so if that helps.

PRESIDING MEMBER GEESMAN: Actually, I think that it is going to take up a larger role in our 2005 report. I think when we issue the scoping memo for that, it will be more clear. I envision us working quite closely with the State Department of Water Resources and with ACWA, the Association of California Water Agencies and the Coastal Commission in reviewing this. We didn't have enough in the way of resources in this cycle to devote what I consider to be adequate attention to this question. We do intend to pick it up in the '05.

MR. BLUE: While I have the mike, I will just continue on with a few other questions. We did provide some information in our written comments that you didn't have prior to this document regarding our property tax we paid, regarding the information, we still have some holes in our information, but we are pulling together the information for the utility user's tax and the franchise fees. They are basically one of the same, it just depends on where you are at.

El Segundo is a utility user's tax and it is called franchise fee. I will note that at El Segundo the utility user's tax revenue makes up about 10 percent of the City's budget. It is a huge number. We get the City folks calling us every week wanting to know how come we are not running because that is revenue they are not getting. It is huge issue for us on how we manager that. It is a huge issue to the City, and we really want to make sure that hopefully you could have some discussion. I don't know if you will have time to do it, but maybe it would be worth having some discussions with some of these cities themselves.

Don't take my word for it, go talk to them and see what kind of impact some of these plants have in the local community. Not only the utility user's tax, but the property tax, but there's also potential redevelopment fees located -- some of these plants as you noted are in redevelopment zones. Redevelopment does occur, they stand to benefit from that financially. I think there is a larger impact to the community than has been recognized in this report so far. I just hope we can look at that.

That is one of the reasons I had recommended this be a separate chapter even. It is just so different than the environmental issues. It deserves its own separate chapter, even if it is a short chapter for now. Maybe it is something that will rolls into next year. I don't know, you may not have time for the rest of this year to get all the information you need, but it is a dramatic issue for a lot of these local communities, so I would hope you would get their input on this.

MR. TRASK: We did consult with at least the planning departments of the jurisdictions, but yes it was difficult to engage all the municipalities on this issue.

MS. ALLEN: Particularly Carlsbad. I tried to get in touch with them a number of times. Now that we've got the specific comment from you. It is something that we can try to allot staff time to in '05.

MR. BLUE: Carlsbad city budget is a lot larger than El Segundo. It just depends on the size of the city budget. Carlsbad budget is a lot larger, so we are not on a percentage basis, not as large. However, they are still revenues that go to the cities.

MR. FLYNN: I guess I would like to comment on that. I'm sure what Greg says is true that -- I mean I would assume that is true, there are probably very many communities that are very dependent upon the revenues, the property tax revenues from these plants. There are also some communities like San Francisco that would dearly love to give up their property tax revenues for Hunters Point and Portrero.

You've got both extremes. While I am on the subject, I thought the write up that was done was technically accurate. I'm not sure it portrays the emotional fervor of the community groups in the City of San Francisco anyway.

MS. ALLEN: Well --

MR. TRASK: That's probably fairly well known among this commission.

MS. ALLEN: -- I think the staff and the commissioners are speaking from personal experience, yes. If you have suggestions, we'd be happy to review them. There was an attempt to present a balanced, reasonably factual portrayal. I've heard the emotional statements, and I have been affected by them. Balance was the attempt there.

PRESIDING MEMBER GEESMAN: I would throw out here, again, in the interest of conservation and resources, some of this stuff is handled best on a case by case basis. Commissioner Boyd and I are both assigned to the San Francisco Generation Project.

Commissioner Boyd is an assigned commissioner on the El Segundo Project, and we have heard from the City of El Segundo in our petroleum infrastructure proceedings. They've chosen to comment on the power plant during those proceedings. I don't think we have heard from Carlsbad, so there in may lie an exception.

On those where there are active siting cases, I think probably the most efficient way for us to get that input would be in the context of those individual proceedings.

COMMISSIONER BOYD: Yes, I would say that we should have in house quite a bit of information since Morro Bay, that was an issue, El Segundo, it is an issue, etc. etc. It probably does deserve a little more discussion which shouldn't be hard to do. I would almost agree that it should be in a separate section. It is not environment. It is tangled up in the whole issue of the structure, the finance of local government in California, and I am afraid you might even have to mention Prop 13 in such a discussion.

There are various kinds of pressures. Some cities are highly dependent, and thus you get a lot of pressure when you have a power plant siting case, and other cities there are other social issues that over ride as indicated. We should at least acknowledge that we are cognizant of it and aware of these force fields that exist at the local level.

MR. BLUE: I think why it is good to acknowledge them is, you know, we have to think back what is the purpose of this report. The purpose of this aging power plant study, in my opinion is it is going to feed into the '04 update or the '03 update I guess. This is the '04 update of the '03 report, which will go to the governor. It will go to the legislature which will hopefully the basis for new state policy.

We just need to present them with all the information we can so that they can make good policy on a going forward basis.

MR. BOYD: I agree. Lots of people's role is just to pass on to the ultimate decision makers all the facts in the context that it exists in the arena in which they operate. In this case, it is within the State of California. This is an issue. We could go to the extreme on the environmental area, for instance, and site all the people who have stated on the record multiple places they don't want anything on the coast of California, and they want those existing power plants picked up and taken away.

There is a range of points of view on many of these issues that are going to be tough to represent.

MR. TRASK: Very good. Any further comments on Chapter 6.

MS. ALLEN: I had a couple of questions for Greg Blue. Greg, you made a general statement in your written comments that you would like to see the land use and socioeconomics discussion expanded.

You focused on expanding the desal discussion, and then more complete data set on socioeconomic contributions, and then acknowledging the contribution of these plants to the local economy. Is there anything else in the land use area?

Initially when I read that, I was wondering whether you were looking for kind of a real estate economics discussion.

MR. BLUE: No.

MS. ALLEN: We aren't set up to do that.

MR. BLUE: No, not looking for real estate economic discussion --

MS. ALLEN: Okay, fine.

MR. BLUE: -- I'm looking for discussions, I would characterize them as favorable contributions to the socio economics of a certain area, such as for one example the lagoon that we have down at Carlsbad, all the activity that we have on that, that we --

MS. ALLEN: Multiple recreational --

MR. BLUE: -- let the YMCA use the inner lagoon for a $1.00 a year. We have the sea bass hatchery for $1.00 a year. There is a ACWA farm, we charge them $1.00 a year. If they were to go out in the real estate market and try to lease property like that today, it would be in the hundreds of thousands of dollars a year. Those types of things which are not dollar contributions, but they are land use sort of contribution to the economies of the local communities is, we think, very important.

When you are looking at the big picture of a certain plant or not -- I'm sure there are other plants probably have other attributes as well that are what I consider positive attributes. Those are the types of things I was talking about.

MS. ALLEN: All right. Thank you for that clarification. When you mentioned the Long Beach plant, are you aware of any plans for repowering that facility?

MR. BLUE: No.

MS. ALLEN: There is a lot of interest in the Port of Long Beach property, some for other energy uses, petroleum infrastructure is a topic we are dealing with. There is also a proposal for a L & G facility in there. So, are you getting any inquiries from the Port of Long Beach or private businesses using the port?

MR. BLUE: Yeah.

MS. ALLEN: You are. Okay, so the future, as far as what will be done with that side is in flux.

MR. BLUE: I would note that it is

listed as a high risk for retirement, and that is accurate unless something changes. I don't see anything changing right now, but it is still good though. I think I can tell you we are in the process of making our final decision on that shortly. We did already notify the ISO in a letter which we sent a letter to the PUC, we didn't send it out to the whole group of people that there are -- I can't remember which -- we retired Unit 8. It was down for a maintenance issue, and we did retire it. We removed that unit from the participating generator agreement. We derated the gas turbins out of there, two MW's a piece. So, we have already done some derating at the facility already, and that has been properly noticed, and we are not hiding the ball as claimed in one of the hearings that the ISO says they are not telling us until afterwards.

We let several people know that is happening. We will be making a decision on Long Beach shortly, very shortly. I'll just go back and say that it is accurate to describe that as a high risk of retirement.

MS. ALLEN: Would it be reasonable to say in the final report that it is a possibility that site may be converted to a non-energy use?

MR. BLUE: No. There are other things you can use that site for, you can put three or four small turbins back in the back. It could be a peaking site. There are other uses. I am saying that facility that is currently sitting there right now is a highly likely for retirement.

PRESIDING MEMBER GEESMAN: I believe that is consistent with earlier announcements your company has made.

MR. BLUE: Correct.

MR. WEISENMULLER: Greg, I have a follow up question on that. In a way, it may apply to some of your combustion turbins in San Diego that I think you retired, but obviously when you bought that plant it had been used by Edison over the years or by San Diego.

My recollection of the divesture agreements were that the utilities were responsible when these plants are retired for decommission the sites for whatever they had done. Somehow you are responsible for decommissioning any additional environmental impact in your period of operation.

If you were to shut down say a Long

Beach, exactly what will happen on a
decommissioning front?
MR. BLUE: I can honestly say I don't
have that answer. Tim, do you have one?
MR. HEMIG: You are referring to an
indemnification, that is a sale agreement that
talks about existing soil contamination. I don't
think it is really relevant to this proceeding,
but the answer is I think at decommissioning that
the owner, us, we are responsible for those costs.
I think that is about the only answer I can
provide on that.
MR. WEISENMULLER: There will be --
there was some sort of compensation on Edison in
that situation.
MR. HEMIG: They were responsible for
the existing soil contamination at the point where
we bought it. I believe there is a portion that
says at decommissioning those become our
responsibility. I'm not totally sure of that, but
I think that is the way it is written.
MR. TRASK: Having worked on
divestitures for the PUC, I believe that is
accurate.
MR. LAWHN: In the case of Reliant, the

recollection I have is in what I would call it is like a 15 year call back provision. It was something like within the first 15 years if you find contamination and you can demonstrate that it belonged to Edison in our case, we could bring Edison back. They would be responsible for coming back in and bearing the cost of that.

That is probably after we probably spend 15 years in litigation over the whole mess, but nevertheless, that is what I recall from our sale. That was nothing to do with decommissioning.

MR. TRASK: Any further comments?

MR. GULIASI: Les Guliasi. I just want to reiterate that we will provide some information about property tax payments, franchise fee payments, charitable contributions, and so forth to the extent that we can get all of the information for all of the years you have requested.

In the general sense that there will be socio and economic impacts to the closure of Hunters Point is well known. Certainly the benefits are well known. In fact, I am hoping that maybe the City of San Francisco would like to stop getting our franchise fee payments for property tax payments for that plant starting now.

Clearly shutting down that plant will have some impacts. There are workers who work in that plant. It has been our policy that to the extent that workers are displaced, they have an opportunity to seek employment in other parts of the company. I think we currently employee about 60 people at Hunters Point.

We have other facilities in the City and County of San Francisco, that really dwarf the facility of that one power plant. We continue to make franchise fee payments and so forth to the City. They are not quite dependent on revenues from that power plant as I noted. As many others have noted, the social benefits, the environmental benefits of the plant closure far exceed the loss of revenues and so forth.

With respect to Humboldt Bay, we have no plans to close down that plant. We employ about 50 people up there on the fossil side. There are others who have responsibility for the nuclear side of that plant. Obviously, the plant is needed for local generation and the nuclear unit is safe store, so we are there, it's there, we are not leaving.

MR. BLUE: Just some closing comments. I just wanted to say at least for the commissioners up here that I really wanted to applaud the staff. This is a really good white paper for the amount of time that they had, which wasn't that long. It is a fairly accurate, fairly thorough document that I think will guide the committee in their committee report. I think you be able to develop some policy recommendations from this report. I think it has been very illuminating on some of these issues. There was some general false assumptions out there that have now the light has been shown on them.

In my opinion, the staff has operated with the utmost integrity in this process. It is overall a really good document. We are looking forward to seeing the committee report next. Thank you.

COMMISSIONER BOYD: Thank you, appreciate that. I know we appreciate that, and I am sure the staff really appreciates that because I know they thought they were handed a greased pig in the beginning of this thing. It took them a long time to tackle it at all.

PRESIDING MEMBER GEESMAN: It is going

to be a crowded fall. I want to thank you all for your participation and your assistance throughout this process.

MR. TRASK: We just got a comment in by e-mail from Steve Moore of the San Diego County Air Pollution Control District. It is fairly short, and I could just read it.

PRESIDING MEMBER GEESMAN: If you would.

MR. TRASK: "Aging power plants in San Diego as defined in this report have had dramatic reductions in NOX emissions in the last four years. However for comparison of the contribution these plants NOX emissions to overall NOX emissions or comparison of other pollutant emission rates, it is somewhat misleading to use annual average emissions. As pointed out elsewhere in the report, aging plants tend to operate much more frequently in the summer, which is also the peak ozone season. The more representative comparison might be using peak daily NOX emissions from these plants in the summer time compared to daily summer time NOX emissions from other sources. In addition, when comparing the emissions of these plants to non-aging load following plants, for example, as in figure 6-6, it is not clear if existing older peaking turbins have been included in the non-aging plants category. These peaking turbins, at least in San Diego, are non-aging only in the sense that they are not included in this study. In fact, they are more than 30 years old and have very high NOX emission rates on the order of 1.5 lbs. per NOX of MW hour or more. These plants should be broken out of any comparison of other load following plants in the reports aging plants sector since they cannot replace most of the aging plant operations because of air permit limitations on their operating time and tend to provide an unrealistically high average NOX emission rates for the non-aging plants."

I'll just briefly respond to that, that yes, the non-aging plant sector does include these, all combustion turbins in the state no matter how old they are.

With that --

PRESIDING MEMBER GEESMAN: If he is still listening, I thank him for submitting that.

We will release our committee draft September 15 or thereabouts, and we would anticipate, then, I think five days of hearings around the state on that draft document before releasing a final set of recommendations October 20, which the full commission will consider at its November 3 business meeting.

Again, I think you all for participating and look forward to seeing more of you in the fall.

(Whereupon, at 3:25 p.m., the workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 26th day of August, 2004.